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September 9, 2011

**<u>Via Email</u>**
**Original via mail**

Ms. Alanna Gillis
Acting Commission Secretary
BC Utilities Commission
Sixth Floor, 900 Howe Street, Box 250
Vancouver, BC V6Z 2N3

Dear Ms. Gillis:

**Re: *FortisBC Inc. 2012 – 2013 Revenue Requirements Application and 2012 Integrated System Plan – Errata 2***

FortisBC Inc. (FortisBC or the Company) provides the following errata to its 2012 – 2013 Revenue Requirements Application and 2012 Integrated System Plan. Replacement pages are attached.

**<u>Errata to 2012 – 2013 Revenue Requirements Application (excluding Tab 6)</u>**

1 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 3 Load Forecast, Page 11, line 7**
“actual” should read “forecast”

2 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 4 Cost of Service, Section 4.3 O&M Expense, Page 45, Table 4.3.4**
Reduction of 2 FTE in 2012F and 2013F
Full Time Equivalents for 2012F should read “555”
Full Time Equivalents for 2013F should read “556”
Reallocation of Labour Expense to Non-Labour Expense
Labour for 2012F should read “33,011”
Non Labour for 2012F should read “21,161”
Labour for 2013F should read “33,733”
Non Labour for 2013F should read “22,061”

**3 FortisBC 2012 -2013 Revenue Requirements Application, Tab 4 Cost of Service, Section 4.3 O&M Expense, Page 48, Table 4.3.4.1**

Reallocation of Labour Expense to Non-Labour Expense

Labour for 2012F should read "1,374"
Non Labour for 2012F should read "913"
Labour for 2013F should read "1,535"
Non Labour for 2013F should read "962"

**4 FortisBC 2012 -2013 Revenue Requirements Application, Tab 4 Cost of Service, Section 4.3 O&M Expense, Page 72, Table 4.3.4.12**

Reduction of 2 FTE in 2012F and 2013F

Full Time Equivalents for 2012F should read "26"
Full Time Equivalents for 2013F should read "26"

**5 FortisBC 2012 -2013 Revenue Requirements Application, Tab 4 Cost of Service, Section 4.7 Financing Costs, Page 118, Table 4.7**

Correction to Column Heading

"Approved 2010" should read "Approved 2011"

**<u>Errata to 2012 – 2013 Capital Expenditure Plan (Tab 6 of 2012 – 2013 Revenue Requirements Application)</u>**

**6 FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 2.2.4 Corra Linn Unit 3 Completion, Page 14, Lines 11-13**

The sentence "Several coils installed during the ULE did not pass quality control standards but remained in the unit due to the high cost to repair" was in error. The sentence should read "There are currently no spare coils available."

**7 FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 3.2.3 Station Urgent Repairs, page 60, Table 3.2.3**

Reduction to 2012 and 2013 Forecast Expenditures

"818" should read "811"
"907" should read "808"

**8 FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 5.2.1 Communication Upgrades, page 96, Line 4**

"North Warfield Substation" should read "Mt. Nkwala Repeater"

9 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 7.0 Demand Side Management, page 117, Table 7.0**

Correction to Benefit/Cost Ratios

“3.9” should read “3.8”
“1.6” should read “1.7”
“1.5” should read “1.6”

10 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 7.0 Demand Side Management, page 118, Table 7.1**

Correction to Benefit/Cost Ratios

“1.9” should read “1.8”
“1.0” should read “0.9”
“3.2” should read “3.1”
“5.1” should read “4.9”

11 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 7.0 Demand Side Management, page 122, Table 7.2**

Correction to Benefit/Cost Ratios

“5.7” should read “5.5”

12 **FortisBC 2012 -2013 Revenue Requirements Application, Tab 6 2012 – 2013 Capital Expenditure Plan, Section 7.0 Demand Side Management, page 124, Table 7.3**

Correction to Benefit/Cost Ratios

“5.7” should read “5.5”
“3.9” should read “3.8”

## Errata to 2012 Integrated System Plan – 2012 Long Term Capital Plan

1 **FortisBC 2012 Long Term Capital Plan, Section 2.9.1 Transmission Line Condition Assessment, Page 129, Lines 7 – 9**

“The program cost forecasts are based on rolling average estimates combined with the Company’s knowledge of the distribution lines expected to be assessed”

should read:

“The program cost forecasts are derived by applying a total cost required to assess the structure (based on historical information and contractual agreements) to the number of transmission poles being assessed. This number is then adjusted for inflation and overhead loading.”

2 **FortisBC 2012 Long Term Capital Plan, Section 2.9.5 Transmission Line Rebuild, Page 135, Table 2.9.5(e)**
Correction to Column Heading
"2012" should read "2013"

3 **FortisBC 2012 Long Term Capital Plan, Section 2.9.5 Transmission Line Rebuild, Page 136, Table 2.9.5(f)**
Correction to Column Headings
"2012" should read "2015"
"2013" should read "2016"

4 **FortisBC 2012 Long Term Capital Plan, Section 2.10.2 Station Urgent Repair, Page 140, Table 2.10.2**
Correction to Project Expenditures
"818" should read "811"
"907" should read "808"
"879" should read "794"
"977" should read "843"
"942" should read "873"
"17,065" should read "15,269"

5 **FortisBC 2012 Long Term Capital Plan, Section 2.10.4 Specific Station Projects, Page 143, Line 24**
"2029" should read "2027"

6 **FortisBC 2012 Long Term Capital Plan, Section 3 Distribution, Page 158, Line 22**
Correction to threshold for live line work
"cannot be used on 25 kV lines" should read "cannot be used on lines exceeding 25 kV"

7 **FortisBC 2012 Long Term Capital Plan, Section 4.3.2.1 Communication Upgrades, Page 190, Line 19**
Correction to equipment name
"North Warfield Substation" should read "Mt. Nkwala Repeater"

**<u>Errata to 2012 Integrated System Plan – 2012 Long Term Resource Plan</u>**

1 **FortisBC 2012 Long Term Resource Plan, Section 4 Load Forecast, Page 42, Line 17**
"0.8" should read "1.2"
"thirty" should read "twenty"

2 **FortisBC 2012 Long Term Resource Plan, Section 5 Resource Requirements, Page 52, Line 5**
Correction to confidence interval range
"28" should read "36"
"72" should read "74"

3 **FortisBC 2012 Long Term Resource Plan, Section 6.4 Preferred Resource Strategy, Page 87, Figure 6.4.1-A**
Correction to Graph Title
"Energy" should read "Capacity"

**Errata to 2012 Integrated System Plan – 2012 Long Term DSM Plan**

1 **FortisBC 2012 Long Term DSM Plan, Section 3.2.1 Updated Avoided Power Purchase Costs, Page 13, Line 14, Line 16, Table 3.2.2**
Correction to Avoided Power Purchase Costs
"$154.15" should read "$143.53"
"$104.32" should read "$101.34"
"$154.15" should read "$143.53"
"$104.32" should read "$101.34"

2 **FortisBC 2012 Long Term DSM Plan, Section 3.2.2 DSM Economics, Page 14, Table 3.2.2**
Correction to Benefit/Cost Ratios
"3.9" should read "3.8"
"1.6" should read "1.7"
"1.5" should read "1.6"

3 **FortisBC 2012 Long Term DSM Plan, Section 3.2.2 DSM Economics, Page 15, Figure 3.2.3**
Correction to Annual DSM Savings in GW.h
Figure 3.2.3 has been updated.
Table 3.2.3 has been updated.

4 **FortisBC 2012 Long Term DSM Plan, Section 3.2.4 DSM Savings as a Percentage of the Load Forecast, Page 16, Figure 3.2.4**
Correction to DSM Savings and Net Load Growth
Figure 3.2.4 has been updated.

If further information is required, please contact the undersigned at (250) 717-0890.

Sincerely,

Dennis Swanson
Director, Regulatory Affairs

## 3.5 LOSSES

System losses consist of:

1. Losses in the transmission and distribution system;
2. Company use;
3. Losses due to wheeling through the BC Hydro system; and
4. Unaccounted-for energy (meter inaccuracies and theft)

Losses are calculated by using a two year rolling average. The forecast gross loss rate for 2012 is the average of the 2009 rate of 9.23 percent and the 2010 rate of 8.42 percent, which is 8.82 percent. The loss rate for 2013 is further reduced to 8.76 percent due to the AMI-based loss reduction program.

## 3.6 PEAK DEMAND

Peak demand is affected by economic activity, the number of customers, UPC and temperature. The Peak demand forecast is calculated by escalating ten years of historical peak load data by the actual historical energy load growth rates and then averaging the output. More detail on peak calculations can be found in Appendix D. Winter peak is estimated to be 721 MW in 2012 and 731 MW in 2013 while summer peak is forecast to be 567 MW in 2012 and 575 MW in 2013.

also offers an employee benefits program for Non-Union employees comprised of pensions, health and welfare benefits, and other work-related benefits. The employee benefits program is targeted to be competitive at the median level of an established group of comparator companies.

***Unionized Employees***

In 2006 FortisBC reached a five year labour agreement with COPE and in 2009 reached a four year labour agreement with IBEW. IBEW wage increases for 2011 and 2012 are 4 percent and 5 percent respectively whereas COPE wage increases are subject to the current round of collective bargaining and have yet to be determined. The last COPE agreement introduced greater flexibility in benefits by implementing a flexible benefits plan.

### 4.3.4 Department Operating and Maintenance Budgets

Following the consolidated O&M in Table 4.3.4 below, is a detailed department level discussion of business responsibilities and budgets.

**Table 4.3.4 Consolidated O&M Cost Summary**

| | General Assumptions | 2007A | 2008A | 2009A | 2010A | 2011F | 2012F | 2013F |
|---|---|---|---|---|---|---|---|---|
| **1.0** | **Full Time Equivalents** | 561 | 564 | 560 | 535 | 552 | 555 | 556 |
| | | | | | ($000s) | | | |
| **2.0** | **Expenses** | | | | | | | |
| 2.1 | Labour | 26,998 | 29,446 | 30,083 | 30,062 | 32,493 | 33,011 | 33,733 |
| 2.2 | Non Labour | 16,003 | 15,279 | 15,935 | 16,086 | 21,392 | 21,161 | 22,061 |
| | | | | | | | | |
| TOTAL O&M EXPENDITURE: | | 43,001 | 44,725 | 46,017 | 46,148 | 53,885 | 54,172 | 55,794 |

#### 4.3.4.1 GENERATION:

***Business Responsibilities:***

The Generation department at FortisBC manages, operates and maintains the Company's four generating stations along the Kootenay River, forming an integral part of the power supply system. These facilities include the Lower Bonnington Dam which was originally constructed in 1897 and upgraded in 1924, the Upper Bonnington Dam constructed in 1907 and extended to incorporate an additional two units in 1940, the South Slocan Dam constructed in 1924 and the Corra Linn Dam which was constructed in 1932. In total, there are 15 units ranging in size from

**Table 4.3.4.1 Generation O&M Cost Summary (2007-2013)**

| | General Assumptions | 2007A | 2008A | 2009A | 2010A | 2011F | 2012F | 2013F |
|---|---|---|---|---|---|---|---|---|
| **1.0** | **Full Time Equivalents** | 103 | 97 | 98 | 96 | 97 | 97 | 97 |
| | | ($000s) | | | | | | |
| **2.0** | **Expenses** | | | | | | | |
| 2.1 | Labour | 1,155 | 1,344 | 1,235 | 1,329 | 1,248 | 1,374 | 1,535 |
| 2.2 | Non Labour | 753 | 550 | 917 | 888 | 939 | 913 | 962 |
| | | | | | | | | |
| TOTAL O&M EXPENDITURE: | | 1,908 | 1,894 | 2,152 | 2,217 | 2,187 | 2,287 | 2,497 |

***Analysis of Forecast O&M Expenditure and Cost Drivers***

Generation O&M expense consists of the costs to operate and maintain the equipment at each of the four generating plants. The largest percentage of this expense is labour and contracted labour.

Over the past five years labour costs have fluctuated as a result of the unit inspection schedule and corrective maintenance projects. The schedule of unit inspection outages changes from year to year due in part to the ULE program, as during the year in which a unit is upgraded no O&M costs are realized on the unit itself and on some ancillary equipment. With the conclusion of the ULE program, these fluctuations in maintenance activities and costs are expected to stabilize.

Over the period under consideration, corrective maintenance projects have also caused fluctuation in labour costs. For example, contracted labour costs and insurance recoveries were recognized in 2007 as a result of the 2006 Lower Bonnington Unit 2 Transformer failure. During the 2009 unit inspection for Upper Bonnington Unit 5, cracks in the turbine were found that required immediate welding repair. Due to turbine cavitation on Unit 6 a weld repair was required in 2007 and 2009 and is expected to occur every two years with the next scheduled in 2011 and 2013. In 2008 the Company also needed to perform corrective maintenance projects which increased labour and materials costs, such as valve failures in the Corra Linn Unit 2 and Unit 3 governors and impellor and piping failures in the Upper Bonnington dewatering systems as a result of the age of this equipment. Seasonally dependent activities also cause fluctuations in labour and contracted labour costs for snow plowing, trash rack cleaning and forebay debris removal. During years of increased snow pack levels these costs increase over average years.

management also includes the proper disposal of expired assets. Old equipment must be collected and delivered to the appropriate recycle locations.

***Business Issues / Challenges***

As technology is used more extensively throughout every area of the business it is important that the Company evaluates the benefits of existing systems and additional functionality available through standard upgrades. This evaluation may involve training and seminars with peers to learn best practices regarding the technology use. It can also require process reviews as technology and business requirements change to ensure the benefits of the most current version of the technology is being realized.

***System Integration Issues***

A number of very robust systems have been implemented over the past five years. The challenge is connecting the core systems and information in a way that is seamless and single point for the end user. The long term strategic plan for IS department is “single sign-on” for all users. “Single sign-on” would be a thin client web style page that would have all the necessary information for individual users presented. The users would simply access the information they needed regardless of what system and database it was in. All requests from the user interface would pass through an Enterprise Service Bus (ESB) that would automatically push and pull information and data to all the appropriate systems. This is a long term strategy that all architecting for new projects and enhancements is based on. There are areas of the business such as customer service and designing that would realize the most benefits from this direction. By connecting these systems, business efficiency could be enhanced.

**Table 4.3.4.12 Information Technology O&M Cost Summary (2007-2013)**

| | **General Assumptions** | **2007A** | **2008A** | **2009A** | **2010A** | **2011F** | **2012F** | **2013F** |
|---|---|---|---|---|---|---|---|---|
| **1.0** | **Full Time Equivalents** | 22 | 26 | 29 | 26 | 27 | 26 | 26 |
| | | ($000s) | | | | | | |
| **2.0** | **Expenses** | | | | | | | |
| 2.1 | Labour | 1,537 | 1,659 | 1,736 | 1,698 | 1,713 | 1,665 | 1,620 |
| 2.2 | Non Labour | 1,328 | 1,174 | 1,202 | 1,126 | 1,102 | 1,176 | 1,226 |
| | | | | | | | | |
| TOTAL O&M EXPENDITURE: | | 2,865 | 2,834 | 2,938 | 2,824 | 2,815 | 2,841 | 2,846 |

markets and the Company's credit ratings. Under the Company's PBR Plan, all variances between approved and actual Cost of Debt are flowed back 100 percent to the customer. The Company's Cost of Equity is determined by the percentage of equity included in the capital structure, and the allowed ROE, both of which are ordered by the Commission. The Company's ROE was approved pursuant to Commission Order G-162-09

The table below provides an overview of the deemed capital structure and the weighted average cost of capital for 2010 through to 2013.

**Table 4.7 Financing Costs**

| | Actual 2010 | Approved 2011 | Forecast 2011 | Forecast 2012 | Forecast 2013 |
|---|---|---|---|---|---|
| | | | ($000s) | | |
| CAPITALIZATION | | | | | |
| Debt | 548,917 | 655,945 | 642,718 | 687,152 | 727,309 |
| Common Equity | 396,927 | 437,296 | 428,479 | 458,101 | 484,872 |
| | 945,844 | 1,093,241 | 1,071,197 | 1,145,253 | 1,212,181 |
| Equity as % of Total | 42% | 40% | 40% | 40% | 40% |
| EARNED RETURN | | | | | |
| Interest Expense | 35,138 | 40,506 | 39,364 | 41,320 | 43,553 |
| Net Earnings | 38,293 | 43,292 | 45,922 | 45,352 | 48,002 |
| | 73,431 | 83,798 | 85,286 | 86,672 | 91,555 |
| RETURN ON CAPITAL | | | | | |
| Weighted Average Cost of Debt | 6.40% | 6.18% | 6.12% | 6.01% | 5.99% |
| Return on Equity | 9.65% | 9.90% | 10.72% | 9.90% | 9.90% |
| Weighted Average Cost of Capital | 7.76% | 7.67% | 7.96% | 7.57% | 7.55% |

### 4.7.1 Cost of Debt

Cost of Debt included in this RRA reflects the anticipated debt issuances and retirements over the forecast period, as well as the interest expense that has been calculated based on embedded interest rates for existing debt, and external forecasts of interest rates for new debt draws and issuances. Debt consists of both Long-term Debt and Short-term Debt.

The following table summarizes FortisBC's annual weighted debt balances and cost of debt for 2010 actual, 2011 Approved and the latest 2011 forecast.

making the structure more brittle, are the primary drivers for replacement. Work completed on Corra Linn Unit 1 indicated that the trash racks on that unit were in very poor condition and were replaced as part of the ULE project for that unit. The risk of deferring this work is a trash rack failure which could result in structural steel components or logs entering the scroll case and damaging the wicket gates or turbine.

Transformer bay oil containment upgrades are required to bring the oil containment for the Unit 3 transformer up to current FortisBC standard. The existing containment is known to leak and in the event of a transformer failure there is a high risk of oil entering the river. The proposed containment will be built to match the containment installed as part of the ULE program for Unit 1 and Unit 2 transformers.Sirpsych0

Spare generator coils specific to Unit 3 are required based on reliability. There are currently no spare coils available. Although testing of coils indicates they are not at risk of immediate failure, any failure of the coils would require an outage of approximately two months to procure and install replacement coils at an approximate outage cost of $0.7 million.

Options considered and rejected were:

- Do nothing or delay project start option was considered and rejected due to reliability and environmental reasons; and
- The option of spreading this project over multiple years was considered and rejected due to the cost benefits of completing the work under one outage.

The total project costs including new trash racks, installation of oil containment and purchase of spare generator coils are estimated to be $0.72 million in 2012.

### 2.2.5 UPPER BONNINGTON OLD PLANT VARIOUS UNIT UPGRADES

The Upper Bonnington Generating facility includes the "Old Plant", originally constructed in 1907 with four generating units averaging 5.8 megawatts (MW) in size. An addition to the facility in 1940 provided two additional generating units approximately 18 MW in size which were upgraded through the Upgrade and Life Extension program in 2004.

Under the Canal Plant Agreement, FortisBC gives control of 12,800 cubic feet per second (cfs) of licensed water to BC Hydro, and in return, BC Hydro supplies an entitlement of 470.2 GWh (and 62 MW) to FortisBC. In order to receive this entitlement, FortisBC is obligated to

**Table 3.3.2 - Station Urgent Repairs Expenditures**

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Actual | | | | Forecast | Requested | |
| ($000s) | | | | | | |
| 418 | 599 | 782 | 639 | 674 | 811 | 808 |

### 3.3.3 STATION ASSESSMENTS AND MINOR PLANNED PROJECTS

This Project involves the condition assessment of the Company's 66 substations for environmental, safety and reliability issues on a ten year cycle, and completion of the work identified during these assessments in subsequent years.

The station assessments and minor planned projects address the whole substation system, which includes equipment such as transformers, breakers, batteries, and ground grids.

The work resulting from the condition assessments is planned and executed in the subsequent years as Station Minor Planned projects. Two of the programs which operate under the minor plan are the program to replace the substation backup battery system, and the program removing gap-type surge arrestors. Both programs are multi-year programs which have been approved in previous capital expenditure plans.

**Table 3.3.3 - Station Assessments and Minor Planned Projects Expenditures**

| 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 |
|---|---|---|---|---|---|---|
| Actual | | | | Forecast | Requested | |
| ($000s) | | | | | | |
| 2,148 | 1,509 | 286 | 286 | 708 | 1,343 | 1,354 |

#### *3.3.3.1 DC Supply Replacement*

A DC (direct current) system is required to operate substation protection and control equipment. The batteries supply these systems in the event of a power outage at the station, and the battery chargers supply these systems when AC (alternating current) power is available, as well as keeping the batteries fully charged. The protection and control equipment operates station breakers and switches and communicates vital information to the System Control Centre regarding the status of system alarms and transformer monitoring devices.

This project will include replacement of battery banks that meet the following criteria:

- **Jungle Mux Laser upgrade** - Current Synchronous Optical Network (SONET) backbone speed in the Kootenay area is an Optical Carrier-1 (OC-1, 50 Mbps), and this is scheduled for upgrading to an OC-3 (155 Mbps) in 2012; and
- **Upgrade Backhaul to Mt. Nkwala Repeater** - Point-Point 900 Megahertz (MHz) MDS LEDR radio has had reliability problems. A replacement 900 MHz or 2 Gigahertz (GHz) link will be examined and installed tentatively in 2013.

Communication upgrades are estimated to cost $0.41 million 2012 and $0.40 million in 2013.

### 5.2.2 SCADA SYSTEMS SUSTAINMENT

This project will fund the annual sustainment requirements for all Supervisory Control and Data Acquisition (SCADA) and Mandatory Reliability Standards (MRS) related infrastructure and software. This includes sustainment for assets such as Survalent Worldview control software, intrusion detection software, document control software, training management software, electronic security devices, physical security devices and monitors, SCADA servers, SCADA Local Area Network (LAN) and Wide Area Network (WAN) devices, workstations and backup infrastructure.

SCADA system sustainment is estimated to cost $0.71 million in 2012 and $0.73 million in 2013.

The 2012-13 DSM Plan was also developed in the context of the DSM Regulation, as discussed in the 2012 Long Term DSM. It includes programs that are mandated to meet the adequacy provisions of the 2008 DSM Regulation, namely measures for rental and low income customers, education (elementary and secondary) and post-secondary schools .

Table 7.0 below is a summary table of the proposed 2012-13 DSM energy savings, expenditures by sector, portfolio level and totals (gross and net of tax), and the Benefit/Cost Ratios for 2012-13 by program sector and overall. There is a significant drop in the energy savings forecast in the 2012-13 plan years, primarily due to an extraordinary industrial project expected to occur in 2011. When the extraordinary project is subtracted from the 2011 savings target of 39,722, the underlying "base" savings target is 32,282 MWh. More details are evident in Table 7.4 (Industrial Programs).

**Table 7.0 - 2012-13 Demand Side Management Plan**

| 1 | Programs | 2011 Approved | | 2012 Plan | | 2013 Plan | | TRC Benefit/ Cost Ratio |
|---|---|---|---|---|---|---|---|---|
| | | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | |
| 2 | Residential | 16,422 | 3,636 | 16,101 | 3,717 | 16,946 | 3,944 | 1.6 |
| 3 | Commercial | 13,940 | 2,118 | 13,380 | 2,199 | 11,980 | 2,085 | 1.7 |
| 4 | Industrial | 9,360 | 613 | 2,480 | 350 | 2,580 | 364 | 3.8 |
| 5 | **Sub-total Programs only** | **39,722** | **6,367** | **31,961** | **6,266** | **31,506** | **6,393** | **1.7** |
| 6 | Supporting Initiatives | | 725 | | 725 | | 725 | |
| 7 | Planning & Evaluation | | 750 | | 740 | | 760 | |
| 8 | **Total (incl. Portfolio spend)** | | 7,842 | | 7,731 | | 7,878 | **1.6** |
| 9 | Income Tax Impact | | (2,078) | | (1,933) | | (1,969) | |
| 10 | **Total deferred (net of tax)** | | 5,764 | | 5,798 | | 5,909 | |

The Lighting and Irrigation programs are included in the Commercial sector due to their relatively small magnitude. The targets for Lighting and Irrigation are provided in the Commercial section.

## 7.1 Residential Sector Programs

Although the number of new homes being built has decreased significantly within the service area since 2008, the renovation and energy retrofit market remains strong. It is expected that the residential sector will continue to provide the greatest amount of savings over the 2012 DSM Plan timeline. The following table outlines the list of residential programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows.

**Table 7.1 - Residential Programs (2012-13)**

| Programs | 2011 Approved | | 2012 Plan | | 2013 Plan | | TRC Benefit/ Cost Ratio |
|---|---|---|---|---|---|---|---|
| | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | |
| Building Envelope | 5,460 | 1,379 | 4,530 | 1,195 | 4,890 | 1,290 | 1.4 |
| Heat Pumps | 3,397 | 694 | 3,397 | 703 | 3,397 | 698 | 1.1 |
| Lighting | 3,420 | 438 | 2,530 | 328 | 2,467 | 313 | 1.8 |
| New Home | 105 | 54 | 90 | 43 | 93 | 45 | 1.2 |
| Appliances | 680 | 245 | 690 | 247 | 739 | 267 | 0.9 |
| Electronics | 180 | 49 | 370 | 58 | 727 | 113 | 3.1 |
| Water heating | 960 | 162 | 1,040 | 186 | 1,383 | 277 | 3.5 |
| Low Income & Rental | 540 | 305 | 1,774 | 677 | 1,570 | 660 | 1.6 |
| Behavioural | 1,680 | 310 | 1,680 | 280 | 1,680 | 281 | 4.9 |
| **Total** | **16,422** | **3,636** | **16,101** | **3,717** | **16,946** | **3,944** | **1.6** |

### 7.1.1 BUILDING ENVELOPE

The major component of the Home Improvement Program (HIP) is building envelope improvements (insulation, air sealing and Energy Star windows and doors). The HIP program will maintain incentive levels from 2011. Program delivery will be primarily through partnerships with LiveSmart BC and will focus on a “whole house” approach. Individual components of the program like heat pumps and Energy Star appliances and lighting will also be marketed separately, as described below.

### 7.1.2 HEAT PUMP PROGRAM

With its temperate winters and hot summers, the FortisBC service area is an ideal climate for energy efficient heat pumps. The program will continue with the current rate of incentives for owners to upgrade electric heating systems to either air source heat pumps, ductless (mini) heat pumps or geo-exchange systems. As an alternative to a direct financial incentives, FortisBC will also provide low-interest loans for qualifying customers at a below market interest rate (4.9 percent).

**Table 7.2 - Commercial Programs**

| 1 | Programs | 2011 | | 2012 | | 2013 | | TRC |
|---|---|---|---|---|---|---|---|---|
| | | Approved | | Plan | | Plan | | Benefit/ Cost Ratio |
| | | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | |
| 2 | Lighting | 7,130 | 1,080 | 7,140 | 1,120 | 7,140 | 1,170 | 1.6 |
| 3 | BIP | 3,010 | 572 | 3,410 | 659 | 3,460 | 696 | 1.8 |
| 4 | Computers | 240 | 34 | 250 | 37 | 270 | 42 | 2.3 |
| 5 | Municipal | 2,980 | 386 | 2,000 | 298 | 530 | 88 | 1.1 |
| 6 | Irrigation | 580 | 46 | 580 | 85 | 580 | 89 | 5.5 |
| 7 | **Total** | **13,940** | **2,118** | **13,380** | **2,199** | **11,980** | **2,085** | **1.7** |

### 7.2.1 LIGHTING

Incentives for lighting measures are varied, with the rebate limited to achieving a two-year payback on incremental cost. Most incentives will be applied at point-of-purchase through product rebates provided through the authorized lighting wholesalers in the FortisBC service area. For specialty lighting and complex retrofits, customers will be encouraged to contact PowerSense directly for a customized rebate.

FortisBC will also promote and incent adaptive street light technologies (street lights capable of dimming), and LED lighting products, for municipalities and customers with large parking lots.

### 7.2.2 LIGHTING DIRECT INSTALLATION PROGRAM

In partnership with LiveSmart BC (Ministry of Energy and Mines), in 2012-13 FortisBC will continue to deliver a lighting direct installation program for small businesses that use less than $20,000 of electricity per year. FortisBC's portion of the incentive for the program is based on an estimate of the kWh saved.

### 7.2.3 BUILDING IMPROVEMENTS PROGRAM (BIP)

Program assistance and financial incentives include a free assessment of the building and where a more detailed assessment is required, 50 percent of the cost of an approved study. FortisBC also will provide rebates towards the incremental cost of efficiency measures compared to standard "baseline" construction The rebate entitlement is based on estimated annual kWh savings, with the maximum rebate calculated to achieve a two-year payback on incremental cost.

controls. In response to requests from irrigation customers, FortisBC has increased the minimum motor size at which “soft-start” pump motor controls are required and simplified the process for approving larger pump motors without “soft-start” controls. Soft-start controls help ensure that electric motors do not affect power quality, but add to the cost of switching to high-efficiency motors.

Product incentives will be offered with Point-of-Sale “instant” rebates through participating irrigation retailers/wholesalers to ensure energy-efficient options are chosen. Irrigation case studies will be profiled in the Powerlines newsletter to raise awareness and attract more participants from this rate class.

## 7.3 Industrial Sector Programs

The following table outlines the two proposed industrial programs, plan costs and savings, and the Benefit/Cost ratio on a Total Resource Cost basis. A description of each incentive program and the primary delivery mechanisms follows. The 2012-13 plan costs and savings are considerably less than 2011 due to an extraordinary project in the current fiscal year.

**Table 7.3 - Industrial Efficiency Programs**

| 1 | Programs | 2011 | | 2012 | | 2013 | | TRC |
|---|---|---|---|---|---|---|---|---|
| | | Approved | | Plan | | Plan | | Benefit/ Cost Ratio |
| | | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | Savings (MWh) | Cost ($000s) | |
| 2 | EMIS | 80 | 10 | 190 | 27 | 290 | 41 | 0.8 |
| 3 | Industrial Efficiency | 1,840 | 231 | 2,290 | 323 | 2,290 | 323 | 5.5 |
| 4 | Celgar | 7,440 | 372 | - | - | - | - | - |
| 5 | **Total** | **9,360** | **613** | **2,480** | **350** | **2,580** | **364** | **3.8** |

### 7.3.1 ENERGY MANAGEMENT INFORMATION SYSTEMS (EMIS)

This is a process optimization program for which FortisBC will provide financial incentives based on calculated energy savings and operational assistance for the purchase of process optimization technology. EMIS will help customers optimize energy efficiency by monitoring and tracking their energy usage on a production basis (kWh/unit). Recommended strategies are identified through an investigation process with additional focus on documentation and training to realize persistence of savings. The customer also agrees to implement all measures identified.

below ground level on all the poles. The condition assessment is aimed at the above ground portion of the pole and reviews the condition of the pole top, anchoring/guying, cross-arms, insulators and other hardware items. Any items which do not pass inspection during the condition assessment are documented and identified for correction in the following year's rehabilitation budget.

The detailed methods and criteria applied in the assessment program are further described in Appendix G. The program cost forecasts are derived by applying a total cost required to assess the structure (based on historical information and contractual agreements) to the number of transmission poles being assessed. This number is then adjusted for inflation and overhead loading. The costs of performing condition assessments vary from line to line depending upon factors including the length of line segment being addressed, the proportion of the line requiring treatment, and the terrain. These factors are taken into consideration when calculating the forecast expenditures.

The program is managed in an eight-year cycle to help levelize both budgets and resource requirements. The condition assessment and test and treat programs are intended to review a complete set of transmission lines within the given assessment year. The eight-year cycle is driven by the chemical treatment applied to the wood poles; this chemical is only effective in preventing rot for approximately eight years.

**Table 2.9.1 - Transmission Line Condition Assessment**

| Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-31 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($000s) | | | | | | | | | | |
| **Cost** | 152 | 639 | 413 | 343 | 469 | 522 | 485 | 480 | 547 | 543 | 10,216 |

### 2.9.2 TRANSMISSION LINE REHABILITATION

The specific rehabilitation projects for various transmission lines involve expenditures for structural stabilization of the defects identified for rehabilitation in previous years' assessments. Included in the scope of work is stubbing of poles, replacement of cross-arms and poles, insulator changes and guy wire changes.

This project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

**Table 2.9.2 - Transmission Line Rehabilitation**

| Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-31 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($000s) | | | | | | | | | | |
| **Cost** | 1,051 | 1,329 | 1,441 | 1,905 | 1,604 | 3,372 | 2,621 | 2,509 | 2,424 | 2,820 | 50,158 |

**19 Line / 29 Line Reconfiguration**

This project involves the transfer of load from 19 Line to 29 Line at the South Slocan switching station and the salvage of 19 Line from the South Slocan switching station to a termination point south of the Passmore substation.

19 Line and 29 Line both originate at the South Slocan switching station and generally run north in the same right of way corridor until they cross Highway 6 just south of the Passmore substation. From this point, 19 Line continues north radially to the Passmore and Valhalla substations while 29 Line is terminated. At this termination point there is a crossbus with inline openers that tie 19 Line and 29 Line together. Historically, 29 Line continued on to Vernon, however now the section of 29 Line after the termination is used as part of Passmore Feeder 1.

At the present time the 12.5 kilometre section of 19 Line that runs in parallel with 29 Line from South Slocan Switching station is in very poor condition and requires rehabilitation/rebuild. As well there is no justification for maintaining both lines that ultimately source the load radially. Since 29 Line in this corridor has recently undergone extensive rehabilitation and is the preferred line to continue to maintain, 19 Line will be salvaged.

The current cost estimate and schedule for the project is shown below.

**Table 2.9.5 (e) - 19 Line / 29 Line Reconfiguration**

| Year | 2013 |
|---|---|
| Cost ($millions) | 0.79 |

**30 Line Lake Crossing Rehabilitation**

30 Line is a 63 kV (Ex-161kV) line that crosses the main body of Kootenay Lake between structures 30L238 and 30L240. The 3.5 kilometre crossing was installed in 1962 and consists off of a 31.75 mm (1.25”) diameter, 91 strand galvanized steel cable. It is supported by steel lattice type towers anchored back using lattice works (integral to the tower) into concrete foundations. The crossing is marked using several 1676.4 mm (66”) diameter marker cones on each of the phase wires. The termination for each tower includes a conductor stress relief section that extends approximately 70 feet out from the deadends.

The following is a high level scope of work for this project;

**Assessment Year (2015, 2014/15 CEP)**

- Structurally assess both of the structures

    - Structures, Foundations, anchoring, etc.
- Electrically assess both of the structures (this will be an upgrade of the existing list of deficiencies)
    - Connectors, Insulators, Hardware, etc.
- Replace the marker cones and assess all of the conductors
    - Dampeners (vibration), Marker Balls, fatiguing, etc.

**Rehabilitation Year (2016, 2016/17 CEP)**

- Paint both structures
- Rehabilitate the structures/line as per the deficiencies captured during the 2015 assessment.

The current cost estimate and schedule for the project is shown below.

**Table 2.9.5 (f) - 30 Line Lake Crossing Rehabilitation**

| **Year** | **2015** | **2016** |
|---|---|---|
| **Cost ($millions)** | 0.80 | 1.52 |

This is an ongoing program to repair failed substation equipment across the service territory. Annual spending varies due to the expected severity and number of equipment failures. The proposed spending is consistent with historical trend.

**Table 2.10.2 - Station Urgent Repairs**

| Year | 2007 | 2008 | 2009 | 2010 | 2011 | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-31 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | ($000s) | | | | | | | | | | |
| **Cost** | 418 | 599 | 782 | 639 | 674 | 811 | 808 | 794 | 843 | 873 | 15,269 |

### 2.10.3 STATION ASSESSMENT AND MINOR PLANNED PROJECTS

The Station Condition Assessment program reviews seven to eight stations per year for items which may impact safety, reliability or the environment. All stations reviewed are tracked in a ten-year cycle. Information gathered during these inspections results in projects planned for the following year in the Station Minor Planned program. Projects conducted under this program can include the replacement of instrument transformers, station service transformers, switches and other equipment that is at end-of-life. Other projects in this program, such as the DC Supply Replacement project and the Gap Type Surge Arrestors Replacement program, increase station reliability

The DC Supply Replacement project replaces failed back-up substation batteries, chargers and distribution equipment. DC station supplies are required to maintain supply to critical protection and control systems that manage risk to station equipment and the communications systems that allow visibility from the FortisBC System Control Center. These systems also help prevent extended fault conditions. DC supplies are load tested on a regular basis to ensure that a station power outage will not affect protection and control equipment operations nor result in adverse operating conditions.

The Gap Type Surge Arrestor Replacement program replaces the existing gap type surge arrestors. This program was introduced in the 2009 - 2010 Capital Expenditure Plan and approved by order G-11-09. Since gap type arrestors are made of porcelain, they can fail violently, damaging adjacent equipment and presenting a risk to personnel in the vicinity. The arrestors being replaced under this program are located on transformers near the transformer bushings to eliminate the risk of an arrester failure removing a transformer from service due to bushing damage.

#### *2.10.4.3 Switchgear Replacement Program (13 kV)*

FortisBC has several stations where the metal-clad switchgear is nearing the end of its operating lifespan. The operating lifespan is based on the condition of the switchgear and the condition of the metal-clad housing. There are a number of stations in the Kootenay region with legacy switchgear including the Crawford Bay, Playmor and Creston substations. The program will complete one replacement every two years starting in 2014 and continuing until 2020.

The switchgear identified for replacement is housed in enclosures without adequate heating, ventilation or air conditioning equipment, resulting in moisture control issues. The legacy metal-clad switchgear is difficult to maintain because parts are no longer available to complete repairs, and must be fabricated, increasing the time and cost of maintenance.

This program will replace or rebuild the switchgear based on asset condition, risk to employees, and system reliability. Alternatives to a complete replacement of the switchgear include refurbishing the metal-clad enclosures and replacing the circuit breaker mechanisms, or installing new outdoor switchgear.

Until the switchgear can be replaced, FortisBC has taken steps to mitigate the risk of arc flash injury to employees and damage to equipment through the implementation of an arc flash detection relay installation program.

The North Okanagan has 40 units of relatively newer switchgear in six locations, the oldest located at the Hollywood substation with one cell manufactured in 1969, and an average age of 19 years. The South Okanagan also has relatively newer equipment, with 13 units ranging from one year old to 16 years old. The Kootenay region has 34 units, with the Playmor, Crawford Bay and Creston stations accounting for 17 units.

The Playmor Substation 25 kV Upgrade project in 2027 has benefits for the switchgear replacement program and would eliminate the need to replace the legacy equipment due to condition-related issues. Instead the switchgear would be replaced with higher-voltage rated equipment to support this capacity and reliability-driven project.

This program is estimated to cost $1.65 million with a projected start date of 2014 and additional $0.98 million in 2016, $1.65 million in 2018 and $1.01 million in 2020.

- **Less Losses -** As voltage increases on a circuit with a fixed load, the line current decreases so that the load demand remains the same. Therefore doubling the voltage will halve the line current. Since the power formula is the product of the square of the current multiplied by the impedance, doubling the voltage will reduce the losses in a line by 75 percent. For example an existing 12.47 kV feeder supplies a feeder with a demand of 1 MVA. The line current is approximately 46 A and the losses in the line are, using 100Ω, 211.6 kW. Using 25 kV with the same conductor (100Ω) and load (1 MVA) the line current is 23 A and the losses are 53.5 kW. Therefore by increasing the voltage by 100 percent, the losses are reduced by 75 percent.
- **Greater Distance -** Because the losses are less in a 25 kV system, the voltage drop along the 25 kV distribution line is also less. This means 25 kV feeders can provide service much farther than 12.47 kV lines. 25 kV is an excellent voltage to use for rural feeders since substations can be near a load centre, but feeders are still able to reach out into the suburbs or outlying areas.
- **Fewer Substations Required -** Historically stations in the FortisBC service territory were supplied at 63 V and spread out approximately every 10 - 20 kilometres using 12.47 kV distribution voltage to serve customers. When the distribution voltage is changed to 25 kV, stations are only required approximately every 30 - 50 kilometres.
- **Similar Operations -** FortisBC work procedures are very similar between 12.47 and 25 kV systems, with the exception of limits of approach. FortisBC's usual distribution hot work (live line) procedures cannot be used on lines exceeding 25 kV, but must instead be completed using transmission procedures.

It is important to note that there is no intent to implement a wide-scale conversion of the existing 13 kV distribution system to 25 kV. Rather, distribution voltage conversion projects will be proposed on a strategic basis where the increased voltage provides clear cost and capacity benefits. It is expected that much of the existing 13 kV system will continue to provide service for decades to come.

Proposed distribution projects and costs are provided in Table 3.0 below.

### 4.3.2 SUSTAINMENT PROJECTS

**Table 4.3.2 - Sustainment Project Expenditures**

| | | 2012 | 2013 | 2014 | 2015 | 2016 | 2017-31 |
|---|---|---|---|---|---|---|---|
| | | ($000s) | | | | | |
| 1 | Communication Upgrades | 410 | 400 | 763 | 776 | 587 | 7,234 |
| 2 | SCADA Systems Sustainment | 707 | 733 | 784 | 811 | 843 | 14,863 |
| 3 | Backbone Transport Technology Migration | - | - | 410 | 6,652 | - | - |
| 4 | Station Smart Device Upgrades | - | - | 704 | 363 | 741 | 3,932 |
| 5 | Telecommunications Ring Closure | - | - | - | - | - | 4,265 |
| 6 | **Total Telecom SCADA Protection and Control Sustainment** | **1,117** | **1,133** | **2,661** | **8,601** | **2,171** | 30,294 |

#### *4.3.2.1 Communication Upgrades*

This project will upgrade and update telecommunications routes and will improve emergency response capability. Some FortisBC telecom equipment is near or beyond its designed operational life. Individual components are unreliable, and the manufacturers no longer supply spare parts. In some extreme cases, equipment can no longer be tested or adjusted because it fails when test systems are operated. This results in delays returning equipment to service. This equipment can also cause failure of the transmission and distribution systems it supports or prevent restoration efforts, exposing the system to possible equipment damage, extended outage times and possibly causing public safety issues. FortisBC plans to pursue a two-fold strategy to address this issue; upgrade parts of the telecom system regularly over several years, and prepare an emergency response plan and supply spare new systems that may be used in emergency restoration.

Specifically, the following projects have been identified:

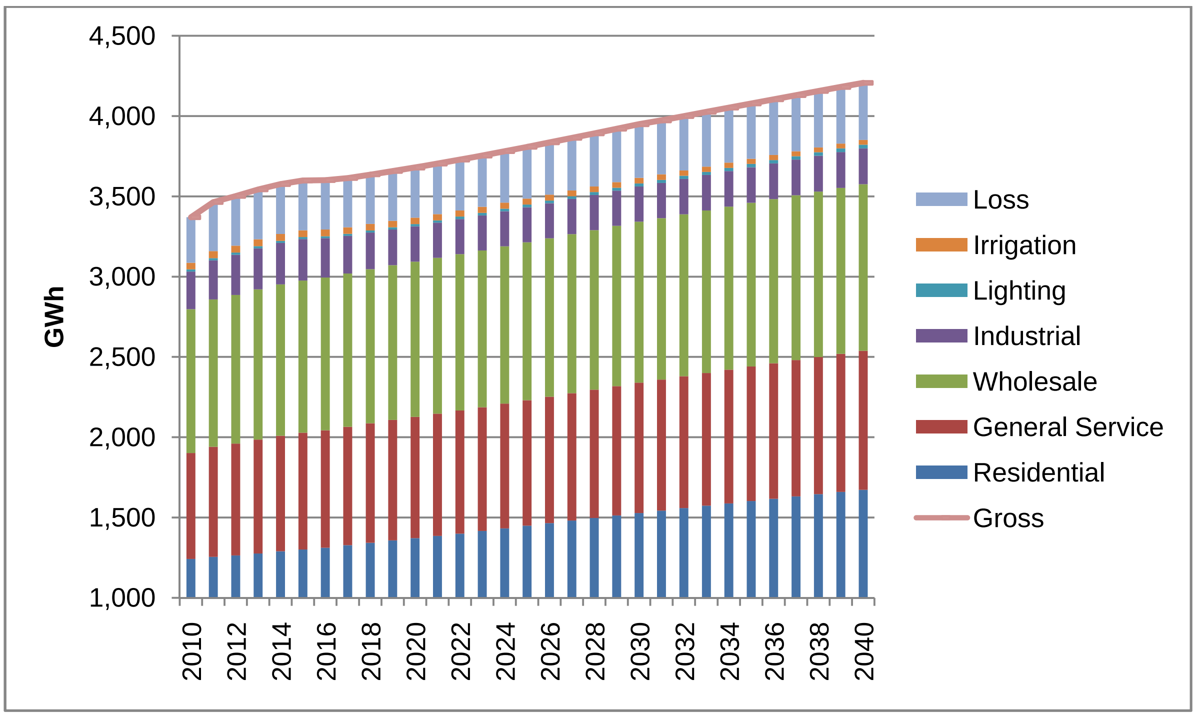
- **Jungle Mux Laser upgrade** - Current SONET backbone speed in the Kootenay area is an OC1 (50 Mbps), and this is scheduled for upgrading to an OC3 (155 Mbps) in 2012.
- **Upgrade Backhaul to Mt. Nkwala Repeater** - Point-Point 900 MHz MDS LEDR radio has had reliability problems. A replacement 900 MHz or 2 GHz link will be examined and installed tentatively in 2013.
- **Distribution Substation Automation Completion** - FortisBC has recently completed a project to automate distribution substations throughout the service region. During these upgrades, some stations were deliberately omitted from the

Inclining Block. Residential sales are recovered a bit by AMI-based Revenue Protection programs until 2021. Gross system load then becomes the sum of total sales and losses. Losses are calculated as a fixed percentage of sales, adjusted for predicted loss savings from the AMI program.

Peak system demand is calculated by escalating an adjusted ten year average of historical peaks by the forecast annual energy growth rates. Peak demand in the Load Forecast does not include Planning Reserve Margin requirements.

Gross system energy load by customer class after being reduced by DSM is provided below for the forecast period.

**Figure 4.1 - Forecast of Energy Requirements by Customer Class (GWh)**




For the first ten years of the forecast gross load after DSM grows at an annual rate of less than 0.9 percent. Industrial, irrigation and lighting loads actually contract very slightly in this period. The decline in industrial growth is largely attributable to a forecast weakening of the forestry sector partly as a result of the mountain pine beetle as well as DSM savings. Irrigation and lighting loads contract because of the impact of PowerSense programs. When considered on a before DSM basis, gross load is forecast to increase at an annual average rate of 1.8 percent in the first ten years of the forecast and by 1.2 percent in the final twenty years of the forecast. By 2040 over half of the energy load growth has been met by DSM.

#### 5.1.4 DEMAND SIDE MANAGEMENT RESOURCES

FortisBC has set a target to avoid 50 percent of annual load growth via DSM measures. However, given the inherent non-firm nature of DSM resources, and the long lead time required to implement alternative supply resources, the Company has considered a probabilistic approach which targets 50 percent DSM effectiveness with an 80 percent confidence interval that projected demand avoidance will fall within the range of 36 percent to 64 percent of status quo load growth.

This spread of possible actual DSM contributions is an important component in developing the potential range of supply gaps that this 2012 Resource Plan must address (as further discussed in Section 5.2 below).

For a detailed discussion of the Company's DSM programs, see the 2012 Long Term DSM Plan filed June 30, 2011.

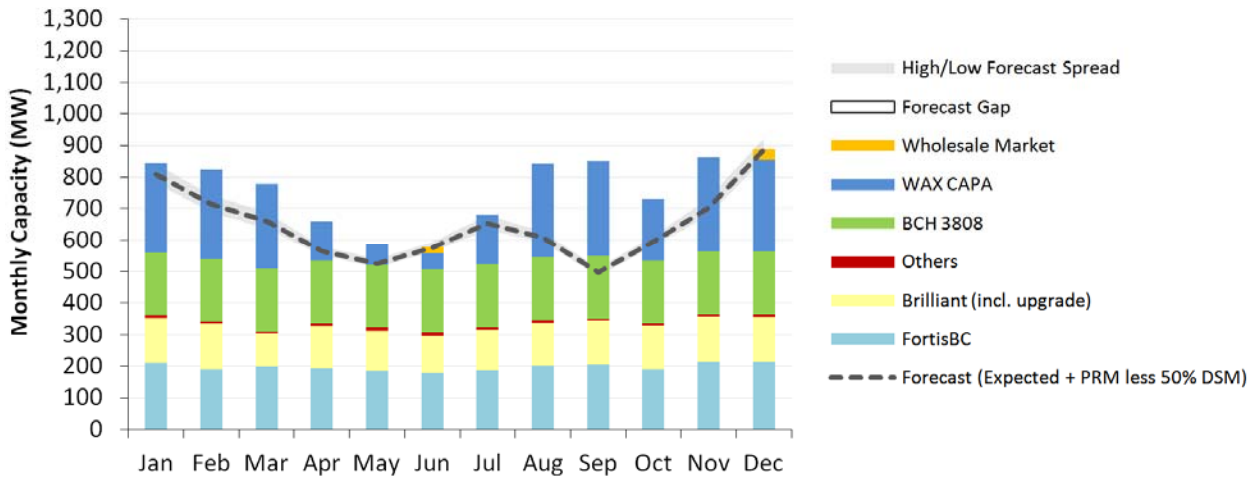
## 5.2 Resource / Load Balance Analysis

With the addition of WAX CAPA to FortisBC's supply portfolio in 2015, FortisBC will have mitigated most of its existing capacity shortfalls. When the Planning Reserve Margin (PRM) is included, the Company still has limited capacity constraints at certain times of the year, as discussed in Section 5.2.1.2, below. In addition, the Company is currently winter energy constrained and the size of the energy gap grows steadily throughout the planning period of this 2012 Resource Plan.

The actual resource / load gap will depend upon load growth, DSM effectiveness and the availability of existing contracts, in particular the renewal terms of the BC Hydro PPA.

- **Load Growth:** FortisBC's load is expected to grow over time. The primary factor influencing the pace of residential load growth is customer count. However, other factors such as widespread adoption of new electric technologies (e.g. electric vehicles) and societal changes (e.g. a move to smaller residences) may have significant impacts. FortisBC recognizes that there are considerable uncertainties regarding forecasts and particularly those which extend far out into the future. As described in greater detail in Section 4, FortisBC prepares a Monte Carlo forecast to determine a high forecast which has a 90 percent probability of not being exceeded and a low forecast with a 10 percent probability of not being reached.

**Figure 6.4.1-A - FortisBC – Preferred Strategy Capacity Gap Closure**




In the long term (2021-2040) FortisBC will transition from the Buy Strategy to a Build Strategy to provide capacity. Because of the higher uncertainties associated with forecasting far into the future and the market price risks, FortisBC is not currently planning specific commissioning dates for specific capacity resources. Rather, FortisBC is planning to assess and maintain the set of capacity resource options listed in the Preferred Strategy Table 6.4.1 and summarized as follows:

- 1 to 2 x 42 MW SCGT
- 100 - 200 MW PSH
- 60 MW Similkameen Hydroelectric Project

Depending on actual load growth, BC Wholesale market prices and estimated market risks, FortisBC will re-evaluate when and which resources to commission in the next FortisBC Resource Plan to be filed with the Commission.

In conclusion, this Resource Plan contains no planned capital expenditures for capacity resources at this time.

The Preferred Strategy also relies on the wholesale energy market in the short term (2011-2015) and medium term (2016-2020). In the long term (2021-2040), FortisBC plans to transition from the Buy Strategy (purchasing from the Wholesale market) to the Build Strategy. The Preferred Strategy contemplates new clean energy resources and the Similkameen Hydroelectric Project.

products regulated beforehand, or by modification of the ramp rates for affected measures – for products anticipated to be regulated in future years.

The 2011 DSM Plan, including supporting documentation (End use Surveys, CDPR, Consultation Report), was filed on June 18, 2010 and received approval Dec 17, 2010 by way of Commission Order G-195-10.

## 3.2 Overview of 2012 Long Term DSM Plan

The 2012-30 DSM Plan is essentially a multi-year extension of the approved 2011 DSM Plan, with a limited number of changes such as updating the avoided power purchase costs used to calculate the DSM benefits, and removing any programs with a Benefit/Cost ratio less than 0.7.

### 3.2.1 UPDATED AVOIDED POWER PURCHASE COSTS

The blended long-term avoided power purchase costs have been updated, based on the portion of energy procured from BC Hydro. The CDPR determined the levelized BC Hydro avoided energy costs to be $143.53 per MWh, and the 2011 Market Assessment was used to determine the Company's long-term marginal energy costs as $84.94 per MWh. These are firm energy prices, inclusive of capacity benefits. The resulting blended cost of $101.34 per MWh, shown in Table 3.2.1 below, is used to determine the benefits of the programs.

**Table 3.2.1 – Long-Term Avoided Power Purchase Costs**

| Component | Source | Long-term Avoided Cost | Proportion | Blended |
|---|---|---|---|---|
| Energy ($/MWh) | BC Hydro 2007 CPR<br>2011 Market report[4] | $143.53<br>$84.94 | 28%<br>72% | $101.34 |

### 3.2.2 DSM ECONOMICS

Under the Act and section 4 of the DSM Regulation, the Total Resource Cost test is the primary determinant of cost-effective programs. The Total Resource Cost is the incremental measure cost, which includes the DSM incentive paid to the customer, plus the program administration cost. The benefits are the present value of each measure's energy savings over the effective measure life, valued using the long-term avoided power purchase cost presented in Table 3.2.1 above.

[4] Midgard FortisBC Energy Market Assessment (Apr 4, 2011) Table 5.1.3.3-A: BC Hydro Mid-C Forward Price Curve (30 Years)

Using the proposed 2012 mix of DSM programs (see 2012-13 Capital Plan DSM Plan filing) the overall Benefit/Cost ratio in 2012-13 is expected to be 1.5, with sector Benefit/Cost ratios as follows:

**Table 3.2.2 – Benefit Cost Ratios by Sector**

| Sector | Benefit/Cost Ratio |
|---|---|
| Residential | 1.6 |
| Commercial | 1.7 |
| Industrial | 3.8 |
| **Sub-total Programs only** | **1.7** |
| **Total (including Portfolio costs):** | **1.6** |

The overall Benefit/Cost ratios presented above, and in the sector tables of section 7 (DSM) of the 2012-13 Capital Plan, have been developed using the 2010 CDPR measure savings and costing data and the avoided costs presented in Section 3.2.1. In this plan, FortisBC has included all programs identified in the Conservation Potential Review reports in which the program TRC ratio is above unity, which supports the objective of pursuing all cost-effective DSM. Over the time span of the 2012 DSM Plan the avoided costs will likely change, as will the measure costs, but the Company will ensure that the Benefit/Cost ratio of the future program mix will be above unity and continue to meet the requirements of the DSM Regulation.

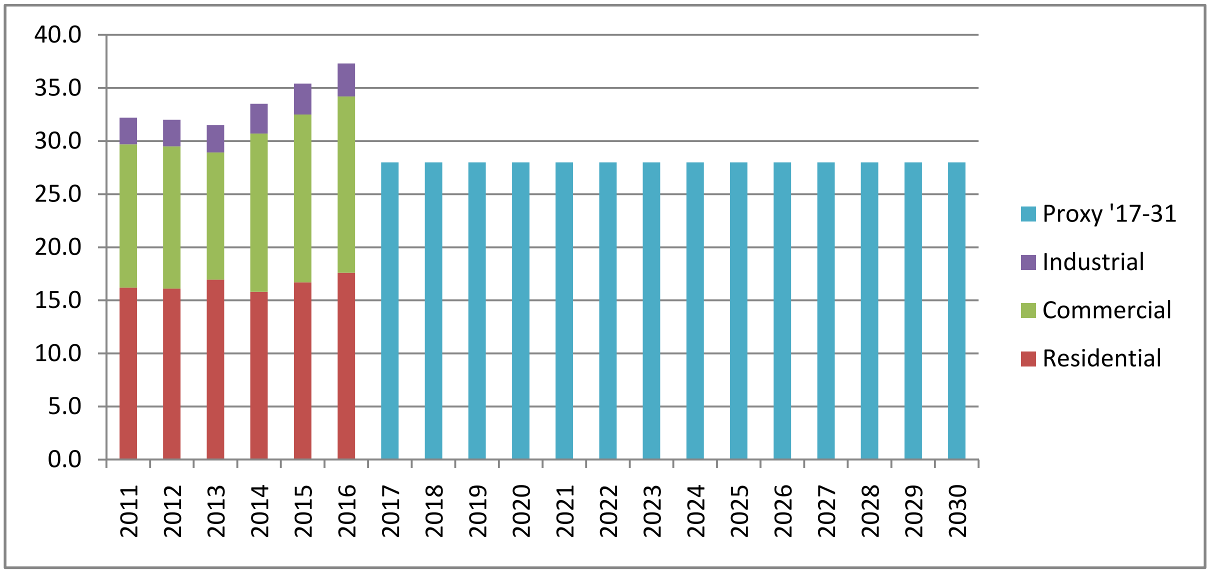
### 3.2.3 DSM SAVING ESTIMATES BY SECTOR

The 2012 DSM Plan includes programs for the residential, Commercial (which includes commercial, street lighting and irrigation rate classes), and industrial sectors. The programs are described in Section 3.4 of this document. The annual DSM target savings (GWh/year) per sector are shown in Figure 3.2.3 below. The energy savings fluctuate over the time frame as the various measures have different ramp rates which escalate, plateau and then decline or mature, as identified achievable potential is exhausted.

The DSM input into the load forecast is shaped to suit the needs of Resource Planning, by disaggregating the three primary sectors into rate classes, and shaping the annual targets into monthly acquired savings estimates.

The DSM plan figures are used for the period 2012-2016 inclusive, since there is a higher level of certainty over that time period. From 2017 onwards a constant target of 28 GWh/year of DSM savings is used as a proxy for future DSM Program savings. Use of this proxy figure reflects the lesser certainty of DSM Plan figures going farther into the future, while fulfilling the *BC Energy Plan* target of a 50 percent load growth offset.

**Figure 3.2.3 – DSM Savings (GWh/year) by Sector**




The tabular data of savings targets, in GWh/year, for the above bar graph is as follows:

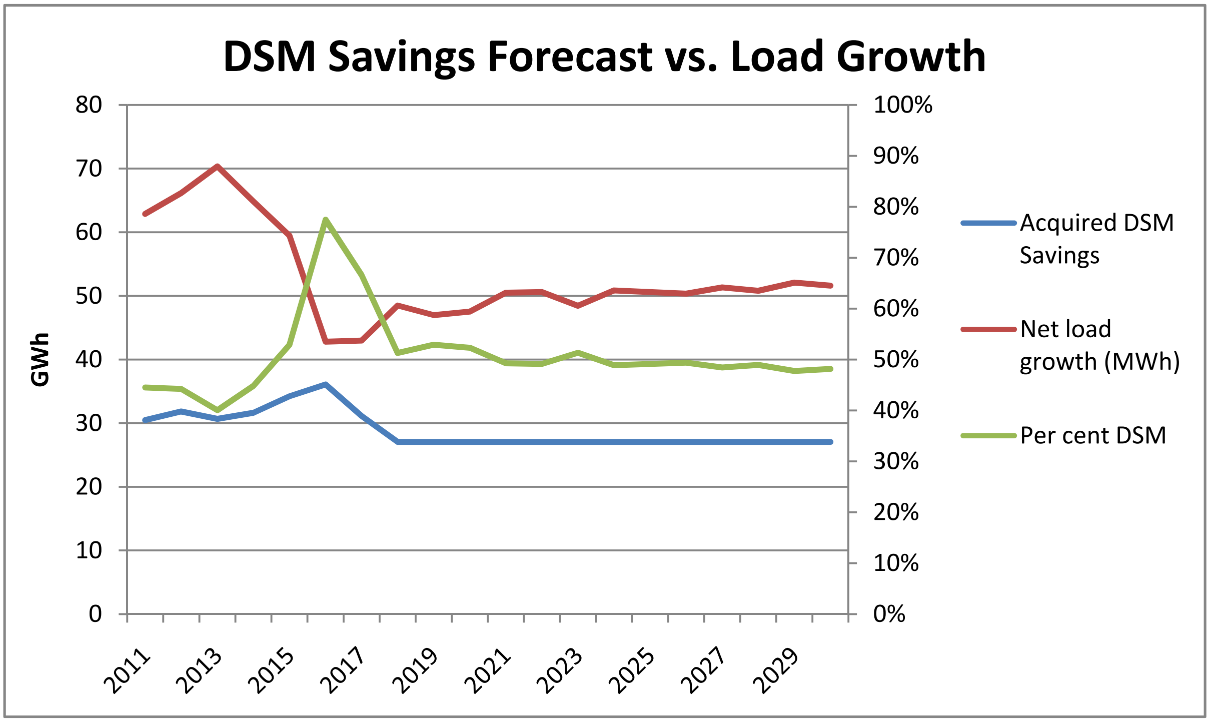
**Table 3.2.3 – Savings Targets**

| Year | Residential | Commercial | Industrial | Proxy '17-31 |
|---|---|---|---|---|
| | **GWh** | | | |
| 2011 | 16.2 | 13.5 | 2.5 | - |
| 2012 | 16.1 | 13.4 | 2.5 | - |
| 2013 | 14.2 | 13.4 | 2.5 | - |
| 2014 | 15.8 | 14.9 | 2.8 | - |
| 2015 | 16.7 | 15.8 | 2.9 | - |
| 2016 | 17.6 | 16.6 | 3.1 | - |
| 2017-30 | - | - | - | 28 |

#### 3.2.4 DSM SAVINGS AS A PERCENTAGE OF THE LOAD FORECAST

The *BC Energy Plan* set a target of 50 percent of incremental resource requirements to be met by DSM. The 2012 DSM Plan targets, in MWh and percentage of incremental load forecast is shown in Figure 3.2.4 below:

**Figure 3.2.4 – Acquired DSM vs. Load Growth Forecast**




The individual years' DSM load offset ranges considerably from 40-77 percent, primarily due to a decrease in forecast load growth, before levelling out in 2018. The cumulative impact of DSM, over the 2011-20 period, ending in the milestone year of 2020, is 51 percent which exceeds the *BC Energy Plan* target by a small margin.

### 3.3 Planning and Evaluation

Planning and evaluation of the DSM initiatives are required to properly plan and control the proposed DSM expenditures and ensure the resource acquisition goals are prudently met. This component includes provisions for the programs manager, technical and reporting staff, as well as external expertise and facilitating meetings of the DSM Advisory Committee (which is comprised of individual customers, organizations representing customers and stakeholders with an interest in DSM).