2012 Integrated System Plan
(2012 ISP)

Volume 1

June 30, 2011

FortisBC Inc.

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1. FORTISBC'S 2012 INTEGRATED SYSTEM PLAN

In its 2012 Integrated System Plan (2012 ISP), FortisBC Inc. (FortisBC or the Company) outlines its long-term strategic direction in the areas of capital, resource and energy conservation. The 2012 ISP is organized as follows:

Volume 1:

1. 2012 ISP Introduction, which describes the Company's recent history and provides an overview of major factors in the external environment that influence FortisBC's planning and operations. The 2012 ISP Introduction also describes the public consultation process undertaken by the Company to ensure that stakeholders were provided with an opportunity to learn about, and provide input into, the 2012 ISP during its development phase.
2. The 2012 Long-Term Capital Plan, which describes the full range of FortisBC's assets and infrastructure, including Generation, Transmission and Distribution, Telecommunications, and General Plant components comprised of Buildings, Information Technology, Fleet and other categories of assets; and

Volume 2:

1. The 2012 Resource Plan, which identifies the Company's future supply requirements and focuses on FortisBC's plan in its acquisition and management of new power resources in order to ensure that the actions the Company takes now are reasonable over a 30 year planning horizon.
2. The 2012 Long-Term Demand Side Management Plan, which describes the Company's plan on how to fulfill provincial policy and enabling regulations that places demand side management as the priority resource to meet growing electricity demand in British Columbia.

The 2012 ISP is being filed concurrently with, and provides the long term context for, FortisBC's 2012 – 2013 Revenue Requirements Application, which contains the Company's 2012 – 2013 Capital Expenditure Plan. Collectively, the 2012 – 2013 Revenue Requirements and the 2012 Integrated System Plan are referred to as the Application.

As described in Tab 8, Approvals Sought and Proposed Regulatory Process, of the Application, the Company seeks the Commission's acceptance under section 44.1(6) of the *Utilities Commission Act* (the Act) that the 2012 Integrated System Plan, comprised of the components identified above, is in the public interest.

2. DESCRIPTION OF FORTISBC

FortisBC is an investor-owned, integrated utility engaged in the generation, transmission, distribution and sale of electricity in the southern interior of British Columbia. Incorporated in 1897, the Company serves more than 161,000 customers directly and indirectly, and employs approximately 560 full time and part time people.

FortisBC owns assets with a gross book value in excess of $1.2 billion, including four hydroelectric generating plants, Lower Bonnington, Upper Bonnington, South Slocan and Corra Linn, and associated dams located on the Kootenay River with a combined capacity of 223 megawatts. Approximately 7,000 circuit kilometres of transmission and distribution power lines are used for the delivery of electricity to major load centers.

FortisBC is a wholly-owned subsidiary of Fortis Inc., which is the largest investor-owned distribution utility in Canada. The Company's regulated affiliates in British Columbia are the FortisBC Energy utilities comprised of FortisBC Energy Inc., FortisBC Energy (Vancouver Island) Inc. and FortisBC Energy (Whistler) Inc., previously the Terasen Gas group of companies.

The Company's service territory is shown in Figure 2.0 below.

Figure 2.0 – FortisBC Service Territory

3. TRANSITIONAL YEARS

In 2004, the Company filed its last long-term development plan, the 2005 - 2024 Transmission and Distribution System Development Plan (the 2005 SDP). Since then, FortisBC has seen significant changes in its operating environment. Not only have transformations occurred within FortisBC as an organization, the environment in which the utility operates has also changed and continues to change. The Company has to respond to those external changes.

In this section, the Company will describe the benefits from the Company's organizational changes in recent years, while the external operating environment will be detailed in the following Section 4.

In 2004, FortisBC became a wholly-owned subsidiary of Fortis Inc. Since then, the Company has begun to realize benefits as a result of its relationships with its parent and affiliates. The benefits from the relationships are reflected in the following areas:

- Strong Relationship with Customers, the Regulator, First Nations and Other Stakeholders;
- Streamlined Corporate Functions;
- Access to Capital;
- Customer Satisfaction; and
- Leveraged Purchasing Power of Goods and Services.

Repatriating Corporate Functions

One of the priorities for the Company beginning in 2004 was to repatriate the corporate functions of the business to the service territory. The repatriation was substantially complete by 2006. As a result, 120 new employees were added to staff corporate functions including customer service, information systems, finance, human resources, communications, and legal and regulatory affairs.

Capital Investment

Substantial capital investment was required to increase reliability, capacity and customer service throughout the Company's service territory. Since 2005, FortisBC has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure.

Recently, the Company's parent company Fortis Inc., along with Columbia Power Corporation, invested in the development of the Waneta Expansion hydroelectric project near Trail, BC, a project with characteristics uniquely suited to FortisBC's resource requirements. FortisBC has entered into a long term purchase agreement for a portion of the output of the Waneta Expansion, beginning in 2015. This long-term agreement defers the need for the Company to acquire new generating facilities, as is described section 5.1.2 of the 2012 Resource Plan component of the 2012 Integrated System Plan.

Customer Satisfaction

FortisBC's continued focus on safety, customer service, efficiency, productivity, and community engagement has resulted in increased customer satisfaction. For instance, customer satisfaction with the Company, as measured by quarterly surveys, rose from a score of 7.1 on a scale of ten in the third quarter of 2005 to 8.0 one year later, and has remained at or above a score of 8.5 consistently since the third quarter of 2006.

Building on the achievements during the transitional years, the Company's primary objectives include:

- delivering safe and reliable power cost-effectively;
- maintaining or improving customer satisfaction; and
- being environmentally responsible.

FortisBC and the Canadian electricity sector face a number of challenges: meeting new demand while simultaneously replacing aging infrastructure and achieving continuous improvements in emissions reduction efforts and overall environmental performance. Electricity infrastructure projects and operations are subject to multiple pieces of legislation and regulation falling under the jurisdiction of various agencies and orders of government, each of which may have a different mandate and jurisdictional obligation.

Specific to the Company's service territory in British Columbia, the Company has identified the following major challenges in meeting the future needs of its customers:

- Maintaining its existing infrastructure;
- Meeting growing demand for reliable electricity;
- Meeting dynamic public policy and legislative requirements;

- Managing customers' bill impacts; and
- Being responsive to customers' input and priorities.

4. MEETING CHALLENGES FROM EXTERNAL OPERATING ENVIRONMENT

There are six major external factors that require the Company to respond in order to reliably, safely, and cost-effectively deliver electricity to its customers in its service territory and that have influenced the Company's 2012 Integrated System Plan. These factors are:

- Customer Growth,
- Provincial Energy Policy, Legislation and Regulation
- Federal, Provincial and Local Governments
- First Nations Relationship
- Health, Safety, Security, and the Environment
- Customer Expectations

Each topic has a direct impact on the Company's operation in both short-term and long-term, and is further discussed below.

4.1 Customer Growth

The size and timing of capital-intensive investments in generators, transmission lines, substations and distribution lines are driven by customer demand for electricity and have direct and considerable implications for electricity acquisition and capital investment decisions and hence on customer service reliability and customer rates. The forecasting of electricity demand, therefore, is the starting point in the resource planning and system planning processes. The risk of substantial deviations of the actual demand from forecast demand is over-supplying of power, overbuilding of supply facilities, or curtailment of customer demand.

As the economy improves following the economic downturn in late 2008 and 2009, FortisBC is expecting moderate levels of customer growth. For the FortisBC electric service area, customer growth is expected to average 1.5 percent for the years 2012 to 2016, mainly driven by continued population growth in the Okanagan region. This compares to the 2.3 percent average annual growth rate from 2004 – 2008, which slowed to one percent in 2009. A more extensive discussion of customer growth and the determining methodologies is found in the Load Forecast included as Tab 3 of the Company's 2012 - 2013 Revenue Requirements Application (2012-13 RRA).

4.2 Provincial Energy Policy, Legislation and Regulation

Provincial energy policy, legislation and regulations affect the Company's operations. The 2007 BC Energy Plan provides the framework for provincial energy policy, and the policies set out in the BC Energy Plan have been given effect in several pieces of legislation, including the *Clean Energy Act*. The 2008 Amendment to the Act makes "British Columbia's energy objectives" pertinent to FortisBC in the context of long-term plans, applications for Certificates of Public Convenience and Necessity (CPCNs) and applications for approval of expenditure schedules. The *2007 Energy Plan* and legislation relevant to FortisBC and its future planning and operations are further summarized below.

4.2.1 2007 ENERGY PLAN

In 2007, the provincial government introduced the *BC Energy Plan: A Vision for Clean Energy Leadership* (*BC Energy Plan*). The *BC Energy Plan* sets forth several goals and objectives, including:

- Setting a conservation target for BC Hydro to acquire 50 percent of incremental resource needs through conservation and efficiency by 2020;
- Ensuring a coordinated approach to conservation and efficiency is actively pursued in British Columbia;
- Encouraging utilities to pursue cost effective and competitive demand side management Opportunities;
- Committing to maintaining clean or renewable electricity generation that would account for at least 90 percent of total generation;
- Achieving self-sufficiency to meet electricity need by 2016; and,
- Establishing the $25 million Innovative Clean Energy Fund.

These objectives and goals are further refined or developed in the subsequent legislation or regulation and are directly relevant to FortisBC's operation.

4.2.2 CLEAN ENERGY ACT

The *Clean Energy Act* was enacted in June 2010. Three parts of the *Clean Energy Act* have specific relevance to FortisBC's operations.

First, the *Clean Energy Act* sets forth "British Columbia's energy objectives," which include:

> "(a) to achieve electricity self-sufficiency;
>
> (b) to take demand-side measures and to conserve energy, including the objective of the authority reducing its expected increase in demand for electricity by the year 2020 by at least 66%;
>
> (c) to generate at least 93% of the electricity in British Columbia from clean or renewable resources and to build the infrastructure necessary to transmit that electricity;
>
> (d) to use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources;
>
> …
>
> (g) to reduce BC greenhouse gas emissions
>
> > (i) by 2012 and for each subsequent calendar year to at least 6% less than the level of those emissions in 2007,
> >
> > (ii) by 2016 and for each subsequent calendar year to at least 18% less than the level of those emissions in 2007,
> >
> > (iii) by 2020 and for each subsequent calendar year to at least 33% less than the level of those emissions in 2007,
> >
> > (iv) by 2050 and for each subsequent calendar year to at least 80% less than the level of those emissions in 2007, and
> >
> > (v) by such other amounts as determined under the *Greenhouse Gas Reduction Targets Act*;
>
> (i) to encourage communities to reduce greenhouse gas emissions and use energy efficiently;

…

(n) to be a net exporter of electricity from clean or renewable resources with the intention of benefiting all British Columbians and reducing greenhouse gas emissions in regions in which British Columbia trades electricity while protecting the interests of persons who receive or may receive service in British Columbia."

The Act has been amended to adopt the "British Columbia's energy objectives" as set forth in the *Clean Energy Act*. Section 44.1(8) of the Act specifically requires that the Commission consider "the applicable of British Columbia's energy objectives" when considering a utility's long-term resource plan.

Second, the *Clean Energy Act* mandates that BC Hydro install and put into operation smart meters and a smart grid, and requires the BCUC to consider the province's goals of "having smart meters, other advanced meters and a smart grip in use" by customers rather than those of BC Hydro's.

As BC Hydro proceeds to implement programs such as Feed In Tariffs and continues to operate the various power acquisition activities (Standing Offer Program, Clean Call, Bioenergy Call), it creates some impetus for FortisBC to consider the implementation of similar programs in its service territory in order to maintain provincial consistency and to respond to customers and developers who will want to do business in the FortisBC service territory.

FortisBC's current effort to implement smart metering technology for its customers is evidence of its consideration of the government's goal of "having smart meters, other advanced meters and a smart grip in use" with respect to its customers. However, FortisBC must balance the potential costs and benefits to its customers against the provincial policy when installing such systems.

Third, the *Clean Energy Act* imposes a prohibition on the approval of any hydroelectric projects which would have storage capability in excess of a yet-to-be defined maximum. This provision has the potential to impact FortisBC's development of potential hydro projects in future resource planning.

4.2.3 DEMAND SIDE MANAGEMENT AND DEMAND SIDE MEASURES REGULATION

As mentioned above, the *2007 BC Energy Plan* and the *Clean Energy Act* emphasize the employment of demand side management (DSM) to meet growing electricity demand in British Columbia. Moreover, section 44.1(2) of the *Utilities Commission Act* requires that a public utility's long-term resource plan include "a plan of how the public utility intends to reduce the demand … by taking cost-effective demand-side measures." Demand-side measures are defined to include activities or programs that aim to "(a) to conserve energy or promote energy efficiency, (b) to reduce the energy demand a public utility must serve, or (c) to shift the use of energy to periods of lower demand."

The specific energy objectives set out in the *Clean Energy Act* particularly relevant to FortisBC's DSM planning are:

- To take demand-side measures and to conserve energy, including the objective of the authority (BC Hydro) reducing its expected increase in demand for electricity by the year 2020 by at least 66 percent; and
- To use and foster the development in British Columbia of innovative technologies that support energy conservation and efficiency and the use of clean or renewable resources.

FortisBC recognizes that while the 66 percent reduction target applies to BC Hydro, it is necessary for FortisBC to support provincial energy goals and principles. As FortisBC stated in the 2009-2010 Capital Expenditure Plan application:

> *"The Company is supportive of the Energy Plan goal of having conservation offset 50 percent of cumulative load growth by 2020. Over the last number of years, DSM has offset approximately 25 percent of FortisBC's annual energy growth requirements, thus effectively requiring an overall doubling of the current DSM resource acquisition rate in order to meet the Provincial Government's objective.*
>
> *New programming will include collaboration with government agencies and the other energy utilities in the province to work towards the objectives of the Energy Plan, and to ensure customers in BC are receiving a consistent DSM message."*

In November 2008, the *Demand Side Measures Regulation* was issued under the *Utilities Commission Act*, which imposes the following requirements for a public utility's plan portfolio:

a) a demand-side measure intended specifically to assist residents of low-income households to reduce their energy consumption;

b) if a demand-side measure intended specifically to improve the energy efficiency of rental accommodations;

c) an education program for students enrolled in schools in the public utility's service area; and

d) an education program for students enrolled in post-secondary institutions in the public utility's service area.

The regulation also specifies that the demand-side measures must be cost effective by comparing costs and benefits of the measures.

FortisBC's DSM planning must now also consider the requirements outlined in the *Demand Side Measures Regulation*, and has done so as illustrated in the 2012 Long Term Demand Side Management Plan.

4.2.4 GREENHOUSE GAS REDUCTION TARGETS ACT

In 2007, the Government of British Columbia enacted the *Greenhouse Gas Reduction Targets Act, S.B.C. 2007, c.42* (*GHG Targets Act*). The *GHG Targets Act* sets provincial targets for reducing greenhouse gas emission. Under the *GHG Targets Act*, British Columbia's greenhouse gas emissions are to be reduced by at least 33 percent below 2007 levels by 2020. A further emissions-reduction target of 80 percent below 2007 levels is set for 2050.

On November 25, 2008 GHG interim targets were set by Ministerial Order as follows:

- 2012 – six percent below 2007; and
- 2016 – eighteen percent below 2007 levels.

Reduction of GHG emissions is a key input in evaluating capacity and energy alternatives in the Company's 2012 Resource Plan.

4.2.5 CARBON TAX ACT

The *Carbon Tax Act*, passed in May 2008, imposes a broadly based carbon tax on the purchase and use in British Columbia of fossil fuels such as gasoline, diesel, natural gas, heating fuel, propane and coal. The tax rates, effective July 1, 2010, are based on $20 per tonne per carbon dioxide equivalent (CO_2e) emissions from the combustion of each fuel. The proposed tax rate increases by $5 per tonne for each of the next two years, reaching $30 per tonne by 2012. Specific tax rates will vary for each type of fuel, depending on the amount of CO_2e emissions released as a result of its combustion.

As stated on the website of British Columbia Ministry of Finance, the purpose of the *Carbon Tax Act* is to "ensure that a consistent long term price signal is provided to consumers so that they continue to make the choices required to reduce their fossil fuel use and emissions."[1]

FortisBC has recognized the potential impact of carbon taxes in preparing its 2102 Resource Plan.

4.3 Federal, Provincial and Municipal Governments

Operation and construction of utility infrastructure are subject to a number of approval or licensing authorities of all government levels under various applicable statutes or regulations. In this section, the Company describes certain acts and regulations, as examples, that affect FortisBC's operation in a municipality, and summarizes other federal and provincial statutes and regulations that may potentially affect FortisBC's operation.

4.3.1 MUNICIPAL GOVERNMENT

With the enactment of the *Local Government Act* in 2000 and the *Community Charter* in 2003, municipalities were given greater independence to govern and regulate its own functions and set its own bylaws. As a consequence of these legislative changes, development approval processes and requirements vary from one municipality to the next. Additionally, municipal policies and bylaws such as regional growth strategies, official community plans, zoning bylaws and development permits can also impact FortisBC's operation. FortisBC is endeavoured to follow applicable municipal laws and obtain all applicable approvals when operating within a municipality. The result, however, is the increased complexity of navigating the various approval processes and longer timeline of the approval processes required for FortisBC's capital projects.

[1] British Columbia Ministry of Finance: Myths and Facts About The Carbon Tax
http://www.fin.gov.bc.ca/tbs/tp/climate/A6.htm

Land use management is an example of such complexity that FortisBC faces. Municipal governments, in managing land use, are required to manage land use conform to regulations set forth in the *Local Government Act*. For instance, development permits are governed by Section 919.1 of the *Local Government Act* and allow for more stringent requirements to be placed on land development to protect natural habitat, riparian areas, environmentally significant or hazardous areas, and to govern the form and character of development. Consequently, municipalities are increasing the level of detail required for development applications.

4.3.2 PROVINCIAL AND FEDERAL GOVERNMENTS

In addition to municipal laws, in its operation or capital project development, FortisBC may have to satisfy requirements of various provincial or federal governments, including the Agricultural Land Commission, Ministry of Transportation and Infrastructure, Ministry of Environment, and the International Joint Commission which has jurisdiction over river systems crossing the international boundary. The applicability of the requirements depends on the jurisdiction and context of the project.

In section 4.5 below, the Company provides further details on provincial or federal government's health, safety, and environment legislation and regulations that play a role in the Company's operation.

4.4 First Nations Relationships

FortisBC's effective operating service territory spans approximately 18,000 km^2, with infrastructure on both the traditional and reserve land of numerous Bands and Nations. The relationship between FortisBC and the various First Nations it serves is important to the growth and success of the Company, and is a relationship that FortisBC greatly values.

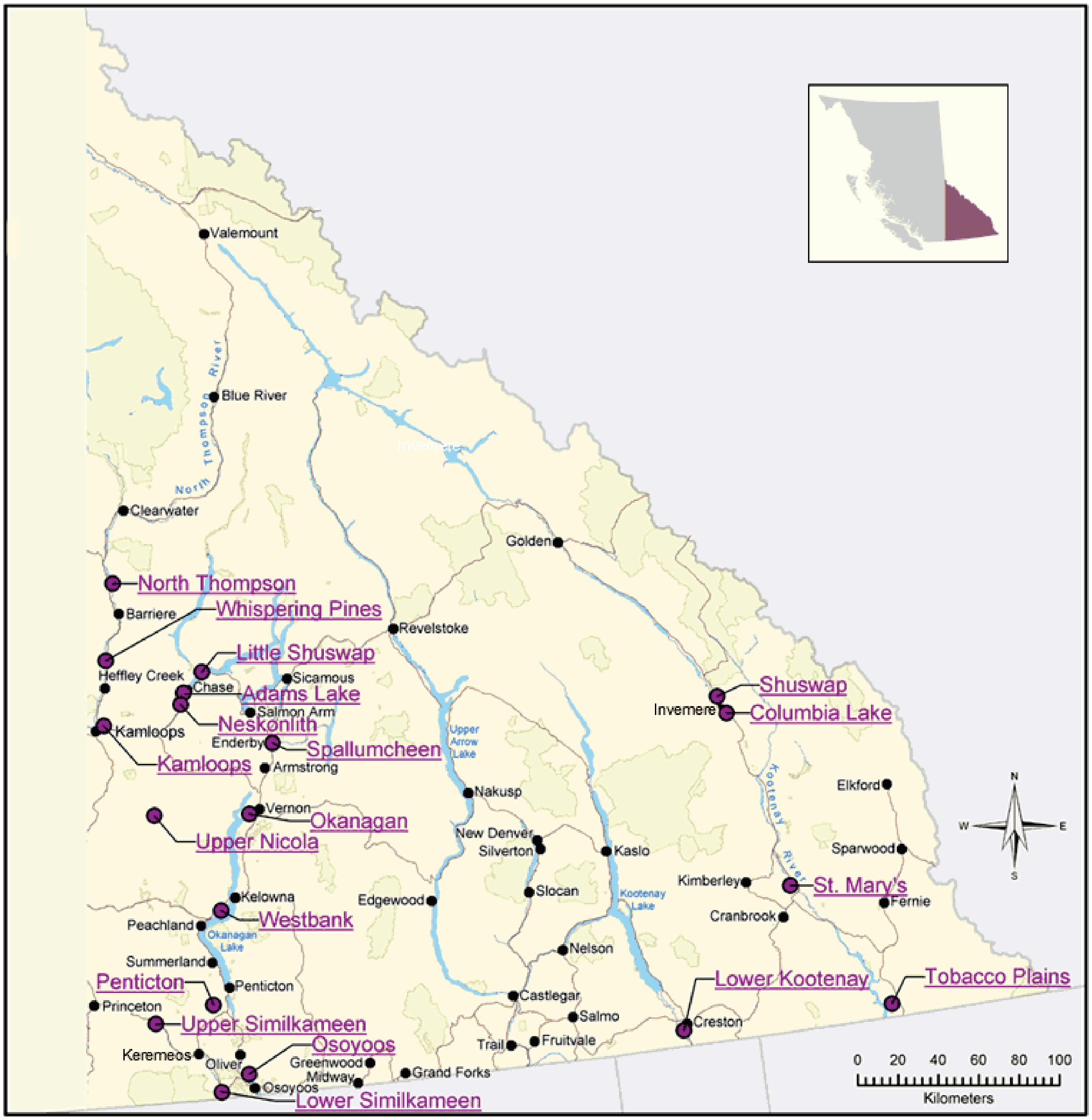
Provided in Figure 4.4 below is a map identifying the various First Nations within and adjacent to FortisBC's service territory. In developing capital projects, FortisBC regularly engages the Okanagan and Ktunaxa Nations, the Shuswap Nation Tribal Council, as well as Bands including Upper Nicola, Okanagan, Westbank, Penticton, Upper Similkameen, Lower Similkameen, Osoyoos and Lower Kootenay. In a project that may potentially affect a First Nation's rights and interests, FortisBC's approach with regard to engagement is defined by a desire to provide an opportunity for First Nations' input in the Company's capital projects, and for the Company to make a genuine effort to address the substance of any concerns or issues raised.

While the Crown has a constitutional duty to consult First Nations and the law concerning the duty to consult is developing, FortisBC has both a desire and need to have a meaningful engagement with First Nations. The current approach used by FortisBC with respect to its First Nations engagement processes has proven to be very effective and successful, as evidenced in various projects including the Nk'Mip Substation Project, the Big White Supply Project, the Benvoulin Substation Project, as well as the Okanagan Transmission Reinforcement Project. Furthermore, the Company monitors new developments on First Nations consultation and engagement requirements for their possible implications.

The Company believes that relationship building with First Nations takes time and effort. FortisBC continues to place strong emphasis on building long-term, constructive relationships with First Nations, and will continue to engage, seek input from, and address concerns raised by the First Nations whose rights and interests may be potentially impacted by the Company's operations. The Company further believes that the Company must operate in a socially and environmentally responsible manner to maintain the trust and support of its customers. The relationships that FortisBC has worked to establish with First Nations are fundamental to making decisions that appropriately reflect and incorporate First Nation interests as well as the interests of the Company and all of its customers. The Company's customers benefit from its careful management of relationships with First Nations as it facilitates timely and cost-effective completion of projects that are necessary for safe and reliable service.

The First Nations consultation process related to the 2012 ISP is described in section 5.2 below.

Figure 4.4 – First Nations by Region (Kelowna Region)



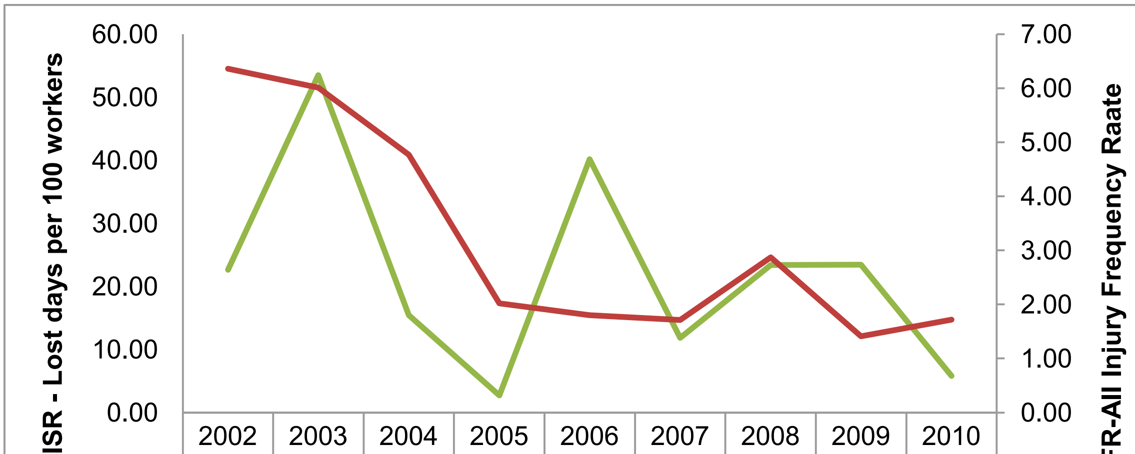
Source: Ministry of Aboriginal Relations and Reconciliation
(http://www.gov.bc.ca/arr/firstnation/maps/map_3.htm)

4.5 Health and Safety, Security, and the Environment

Health, safety, security and environment requirements are another external factor that FortisBC has to consider and address when delivering electricity to the communities it serves. Health, safety, security and environment requirements are constantly evolving because of new legislation or more recent industry best practices. FortisBC uses a Safety and Environment management System to systematically address both safety and environmental risks associated with the construction, operation and maintenance of infrastructure..

FortisBC places significant emphasis on its employees' health and safety. In the last decade, FortisBC has made steady gains in health and safety performance, as reflected in Figure 4.5 below. The figure illustrates a history of accident frequency and severity, as defined by the Canadian Electricity Association *Standard for Recording and Measuring Occupational Injury / Illness Experience and Transportation Incidents.*

Figure 4.5 – FortisBC Injury Frequency and Severity



	2002	2003	2004	2005	2006	2007	2008	2009	2010
ISR	22.64	53.49	15.44	2.70	40.17	11.83	23.37	23.43	5.82
AIFR	6.36	6.01	4.77	2.02	1.80	1.71	2.87	1.41	1.72

Note: Performance statistics based on a January to December calendar year.

As part of its continual improvement process, the Company periodically engages a certified independent auditor to audit the Company's safety system. These audits and their results are described in the Company's 2011 Safety Plan, included as Appendix K of the 2012 – 2013 Revenue Requirements Application.

Overall, the Company has improved its Health and Safety requirements and procedures. Examples of improvement include:

- Qualified professional snow avalanche assessments and plans;
- Crane operator certification;
- Young worker training requirements;
- Notice of project procedures; and
- Confined space hazard assessment and qualifications.

4.5.1 SECURITY OF ASSETS

The security of a utility's asset is taking on an increasingly prominent role within the industry, with issues ranging from prevention of theft of copper from distribution equipment or other facilities to compliance with industry standards, notably the BC Mandatory Reliability Standards (BC MRS), which are based on the North American Electric Reliability Corporation (NERC) standards and establish rules for planning and operating the bulk power system. To maintain the security of the Company's assets, the Company needs not only to comply with established industry standards but also to develop prevention programs. Each aspect is further discussed below.

At the federal level, the Canadian Security Intelligence Service, in conjunction with the Integrated Threat Assessment Centre, is constantly monitoring national security and communicate with regard to any issues that may impact critical electrical infrastructure.

4.5.1.1 Prevention and Mitigation Programs

In keeping with its focus on delivering safe, reliable power cost effectively, FortisBC's first and foremost concern is the safety of its employees and customers. The security of assets has a direct impact on the public and workers' safety. Two types of illegal activities particularly pose a threat to the security of FortisBC's assets, which in turn, threatens the safety of the Company's employees and customers.

First, theft of copper wire creates impairment to the safety systems as a result of the removal of ground leads and violation of the physical security perimeter. This creates significant hazards for both employees and the public. Substations are typically unstaffed and contain large amounts of copper making them attractive to thieves. Historically copper theft was minor with issues being dealt with as they arose. In the past two years the increase in frequency of breaks-ins and copper theft has resulted in increased security at specific job sites and greater vigilance on the part of operations crews. This problem has escalated to the point where these activities contributed to one of FortisBC's Power Line Technicians being injured. Furthermore, any damage to the infrastructure needs to be repaired and stolen equipment replaced resulting in an increase in corrective work.

Power theft is an issue endemic to the electrical industry. As FortisBC staff are interacting with customers on a daily basis (meter reads, connects and disconnects, meter changes) the safety of employees continues to be a concern as these illegal activities are on the rise. In addition to ongoing internal efforts, FortisBC also has contract investigators to help with the growing number of power thefts. The AMI program is expected to address this issue to a large degree.

FortisBC has an ongoing capital security upgrade program for risk mitigation that addresses the highest risk substations based on exposure and reported theft incidents. This program is flexible and is adapted as security techniques and options improve, BC Mandatory Reliability Standards (BC MRS) requirements evolve, and the methods employed by thieves change.

4.5.1.2 Five-year approach to security

In addition to the risk-mitigation program discussed above, the Company has also developed security plans to address the following aspects of the utility operation:

- Cyber security - Cyber security is addressed in part by fulfilling the BC MRS requirements;
- Physical building and asset security - Measures required include limiting access to facilities, installing locked barriers on specific equipment. Physical security at facilities requires measures from rekeying facilities to increasing use of security staffing at key construction sites;
- Theft of assets and resulting collateral damage - Copper theft and violation of grounds is being met by changes in engineering standards to increase use of galvanized wire as an alternative to copper as station fence ground leads and the use of theft deterrent materials such as copper clad steel wire; and

- Theft of power - Power theft will be addressed primarily by the AMI program and secondarily through ongoing efforts such as internal investigations and external reporting by law enforcement agencies.

Over the next five years, FortisBC expects to:

- Establish standards for site security;
- Review standards, procedures and systems in place with other Fortis subsidiaries;
- Actively participate in Canadian Electricity Association activities related to security standards;
- Ensure the integration of security costs into capital projects;
- Audit security department functions on an ongoing basis; and
- Use external audit to measure effectiveness of FortisBC security programs, policies and standards.

4.5.2 ENVIRONMENT

4.5.2.1 Potentially Applicable Legislation

In order to operate FortisBC's transmission, distribution, and generation facilities in an environmentally sound manner, the Company is required, and is committed to, in different aspects of its operation to comply with the requirements of various statutes, including the *Environmental Assessment Act* (British Columbia), the *Fisheries Act* (Canada),and the *International Rivers Improvements Act* (Canada) the *Environmental Management Act* (British Columbia), the *Water Act* (British Columbia), the *Wildlife Act* (British Columbia), and also various regional and municipal government bylaws enabled under the *Local Government Act*. The Company's compliance efforts may result in not only increased capital or operation costs but also lengthened project time.

As an example, the federal *Fisheries Act*, which authorizes work in or near fish bearing waters, may increase project planning by six months or more. Where mitigations or harmful alteration, disruption or destruction may occur, additional time and resources are required to mitigate the issues.

Of the numerous environmental legislative requirements affecting utility operations, two of the most relevant are the *Species at Risk Act* and the *PCB Regulations* under the *Canadian Environmental Protection Act*. The requirements imposed by each of these are described below.

Species at Risk Act

The *Species at Risk Act* (*SARA*) was created to protect wildlife species from becoming extinct and to promote recovery of threatened or endangered species. It requires the government of Canada to provide for the recovery of species at risk due to human activities, and to manage species of special concern. *SARA* not only prohibits the killing, harming, harassing, capturing or taking of species at risk[2], but also makes it illegal to destroy their critical habitats[3].

Where species at risk are identified, the legislation can create additional challenges to obtain approvals for new projects as well as to the ongoing operations of existing facilities. As noted above, *SARA* legislation prohibits any harm to the affected species, usually resulting in increased monitoring around existing facilities and changes to operational plans to ensure no incidental harm to the endangered species occurs as a result of existing operations.

Due to the nature of hydroelectric energy production, transmission and distribution FortisBC can be affected by *SARA* regulations. For example, the listing of aquatic species such as the white sturgeon is considered a concern in the Columbia and Kootenay Rivers near FortisBC hydroelectric plants. Many other aquatic species have been classified as “threatened” under *SARA*, including the Shorthead Sculpin and Umatilla Dace which also occur in waters near the hydroelectric plants. The habitat of terrestrial species either listed or endangered may exist within transmission and distribution line corridors, as well as surrounding substations.

Currently, some uncertainty exists around the management and interpretation of the regulations by various governmental agencies charged with enforcing the legislation. For instance, with respect to aquatic species the Department of Fisheries and Oceans

[2] SARA Section 32 subsection (1) http://laws-lois.justice.gc.ca/eng/acts/S-15.3/page-13.html#h-14

[3] SARA Section 33 http://laws-lois.justice.gc.ca/eng/acts/S-15.3/page-14.html

Canada (DFO) could interpret that some hydroelectric facilities on the river system are out of compliance with *SARA* due to the potential for incidental harm to white sturgeon during normal operations as a result of sturgeon being trapped in a draft tube during maintenance, entrainment of sturgeon through facilities and potential effects on critical habitat associated with flow. The manner in which DFO chooses to manage the risk to the endangered species could result in operational changes.

FortisBC continues to monitor the potential impact of this legislation on its operations, both at its hydroelectric facilities and its transmission and distribution infrastructure with a specific goal of ensuring compliance with the regulations.

PCB Regulation

FortisBC first established a PCB testing and monitoring program in response to Environment Canada's review of the PCB regulations in 2002. At that time, it appeared that the focus of future *PCB Regulations* would be directed at pole-top, underground and pad mount transformers. FortisBC further amplified its efforts to deal with PCB health concerns and environmental concerns upon the release of draft PCB regulations in 2003, which suggested that, depending on levels of concentration, some units of equipment would be required to be removed from service. To ensure worker health and safety and compliance with the pending regulation, in 2005 FortisBC began a multi-year PCB oil sampling and testing program for pole-top, underground and pad mounted distribution transformers.

In September 2008, new *PCB Regulations*[4] under the *Canadian Environmental Protection Act* were enacted. The regulations set specific deadlines, along with enforcement provisions, for elimination of equipment with PCB concentrations at or above 500 mg/kg. Pole top transformers are exempt to 2025, however substation equipment at or above 500 mg/kg was not given the exemption. It also establishes best management practices for the remaining PCBs in use (those with content of less than 500 mg/kg). The regulations now prohibit the release of one gram or more of PCB from operating equipment, and include a zero tolerance for PCB release from scrap equipment.

[4] Canadian Environmental Protection Act PCB Regulations (SOR/2008-273) http://www.canlii.org/en/ca/laws/regu/sor-2008-273/latest/sor-2008-273.html

FortisBC has been granted an extension to 2014 to remove substation equipment and oil containing PCB concentrations greater than 500 mg/kg. All other equipment with concentrations between 500 mg/kg and 50 mg/kg must be removed from service by 2025. This includes instrument transformers, bushings, capacitors, the aforementioned pole-top transformers, and switches, among other types of equipment.

4.5.2.2 Increasing Permit and Approval Requirements

Various federal, provincial, and local government statutes and regulations require the Company to obtain specified permits, licenses and approvals to build, operate or maintain electric utility facilities, and impose increasingly more stringent environmental requirements for obtaining the permits or approvals. These permits, licenses and approvals relate to, among other things, waste disposal, discharges to water, impacts on aquatic habitat at river and stream crossings, and the flows and water level at the Canada - U.S. international boundary. Examples of the permits and approval that the Company often needs to obtain for its operation and construction include:

- Facilities applications;
- Environmental impact assessments (federal/provincial) ;
- Environmental assessment screenings;
- *Fisheries Act* Authorizations (e.g. approved work practices for riparian vegetation management limits. Vegetation management activities around fish-bearing streams to protect and conserve riparian habitat);
- *Species at Risk Act* incidental effects permits;
- *Navigable Waters Protection Act* permits; and
- Provincial approvals for specific work activities or work in specified areas including work impacting watercourses or wetlands, greenhouse gas, herbicide use, and municipal work permits:
    - *Environmental Management Act*;
    - *Water Act*;
    - *Riparian Areas Regulation* and other provincial regulations;

- Habitat Officer's Terms and Conditions for Changes in and about a Stream;
- *Greenhouse Gas Reduction (Cap and Trade) Act* and *Reporting Regulation*; and
- Environmental management plans.

4.6 Customer Expectations

The Canadian Electricity Association (CEA) describes the changing environment for electrical infrastructure development.

> *"Most parts of Canada have not had significant new electricity development for 20 years or more. Infrastructure across the country is reaching the end of its useful life and requires refurbishment or replacement. During the same time period, the environmental assessment procedures and public consultation requirements have changed significantly. The advent of social media also means that any project opponents are able to communicate more effectively and build support for their causes. There is a growing list of electricity projects that have been cancelled due to a lack of public acceptance. All forms of electricity development have seen significant public protest: wind & solar farms, coal plants, nuclear, gas-fired plants, hydro, transmission lines. The not-in-my backyard (NIMBY) phenomenon is now a standard consideration for electricity development initiatives."*[5]

Despite these challenges, seven in ten respondents, or 70 percent, hold a favourable opinion of their electrical utility (CEA, June 2010). The top five drivers cited by the CEA for customer satisfaction include:

- The price paid for electricity
- The perceptions that the company cares about its customers
- The perception that the company is efficient and well-run
- The perception that the company listens to and acts upon customer concerns

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[5] Canadian Electricity Association (2009). Building Tomorrow's Electricity System: Electricity Fundamentals for Decision-Markers (page 11) (http://www.electricity.ca/media/1490-CEAguide_v3selected_v2_WEB_decision_maker.pdf)

- The accuracy of billing

In FortisBC's experience, customer surveys have consistently demonstrated price (electricity cost) and reliability as being the top two concerns for the majority of its customers.

4.6.1 CONSUMER ATTITUDES TOWARDS THE ENVIRONMENT

Demand for clean and renewable energy continues to grow, spurred by public policy and changing consumer attitudes towards the importance of the environment.

The trend towards greener living by consumers continues, although it has been somewhat slowed by recent weaker economic conditions. Results from a survey conducted by Environics Research for The Home Depot Canada, which tracks Canadian consumer attitudes and behaviours, shows that when it comes to environmental initiatives and actions taken at home, consumers remain committed to becoming more environmental friendly. Interest remains high with two thirds of respondents being very interested or somewhat interested in making their homes greener, down somewhat from the 80 percent level the previous year.

The green trend is also evident with small business owners across Canada. A recent survey conducted by the Royal Bank Canada Small Business division indicates that half of Canadian small business owners currently have or are considering implementing a green plan or environmental policies for their business.

This changing attitude towards the environment is also evident with FortisBC's customers. Customers' attitude toward FortisBC operating in an environmentally responsible manner has increased steadily over recent years, rating third or fourth importance in customer service surveys regularly, behind the factors price and reliability.

4.6.1.1 Electromagnetic Fields

FortisBC is aware and sensitive to customer concerns over electromagnetic fields (EMF) surrounding electrical facilities. The Company designs and operates its infrastructure in consistence with the EMF exposure guidelines developed by the International Commission on Non-Ionizing Radiation Protection (ICNIRP), endorsed by the World Health Organization (WHO) and Health Canada, and accepted by the Commission as the appropriate guidelines for considering the safety of EMF levels.

The BCUC has addressed EMF in several previous decisions, most extensively in the Vancouver Island Transmission Reinforcement (VITR) Decision in 2006. In that decision, the Commission concluded that, "In the absence of convincing new evidence that indicates that change is warranted and/or imminent, the Commission Panel concludes that it should not impose lower EMF exposure standards on VITR"[6]. Also in the VITR Decision, the Commission directed BCTC (now BC Hydro) to file a public report with the Commission every two years or sooner that summarizes the latest results of EMF risk assessments and any changes in guidelines developed by the WHO, ICNIRP, Health Canada and others where relevant[7]. FortisBC continues to follow these developments and changes to guidelines as they occur.

FortisBC relies on the conclusions of the professional bodies cited above regarding EMF health risks. The Company employs several precautionary mitigation measures in its designs where they are appropriate and cost-effective, including compact transmission line construction, double-circuiting of lines and feeders, and phase orientation to maximize field cancellation.

4.6.1.2 Social and Environmental Project Considerations

The Canadian Electricity Association reports that "electricity projects across Canada have been stalled or cancelled due to public opposition. Many arguments with varying degrees of merit are employed by project opponents: land use, emissions, wildlife impacts, aesthetics, public health and safety"[8]

Over the past five years FortisBC has noted rising concerns expressed by customers, interveners, and local governments regarding the perceived impact of the electrical infrastructure on individuals and/or communities. Recent decisions of the BCUC have recognized the merit of addressing social and environmental issues when undertaking capital projects. The Commission has stated on a number of occasions that, in considering public convenience and necessity the task is not to select the "least cost"

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[6] VITR Decision, p. 71

[7] VITR Decision, p. 72

[8] CEA "Building Tomorrow's Electricity System", 2009.

project but to select the "most cost effective" project.[9] The "cost-effective" analysis includes consideration a broader range of factors, including a project's characteristics, capital costs, safety, reliability, schedule, financing arrangements, the cost to ratepayers, the impact on the financial capability of the utility, and other impacts.[10]

Some examples of recent BCUC decisions concerning FortisBC capital projects, which illustrate the "cost-effective" approach, include:

- Funding was included in the Arawana substation project for construction of a screening wall around the equipment to reduce the visual impact of the station;
- The Okanagan Transmission Reinforcement project included funds for the development and implementation of and Environmental Management Plan, which included a "no net habitat loss" program;
- In the Benvoulin substation determination, the Commission stated that one of the key drivers in determining site selection for this station was the accepted level of visual impact in the community. The BCUC determined that the evidence suggested the site was "far and away the optimum site in terms of aesthetics and general visual impact to area residents and passers-by"[11].

FortisBC also agreed to additional vegetation screening at the Ellison substation at the request of the City of Kelowna during the re-zoning and Official Community Plan amendment approval process.

FortisBC expects to expend one to two percent of total project cost, in some types of capital projects, to address social and environmental issues. Realizing that project and the communities in which they are constructed are unique, this may include elements such as:

- Landscaping around electrical equipment to improve visual screening and to enhance the local environment;

9 Vancouver Island Generation Project - VIGP, Decision pages 74-77, Vancouver Island Transmission Reinforcement - VITR Decision, page 15; Naramata Substation Project Decision, pages 7-10

10 VIGP Decision, page 77; VITR Decision, page 15

11 FortisBC Benvoulin Substation Project Decision, page 17 (Order C-1-09)

- The purchase of land offsets and additional lands to donate to conservation organizations such as The Nature Conservancy, thus reducing long term impacts of projects on the environment as a whole;
- Design support from design architects and / or landscape architects to mitigate social impacts through design;
- Option for project sites which provide natural boundaries; and
- Additional funds for steel fabrication to reduce "shine" on new electrical equipment.

4.6.1.3 Public Input

As mentioned above, public opinion on land use, emissions, wildlife impacts, aesthetics, public health and safety plays an increasingly active part of the utility's operation and capital project planning process.

When the Company is proposing and developing a project, a number of opportunities exist for the public to provide input into the formal approval process. While these processes are necessary, it presents challenges to the Company's operation and planning of capital projects.

For instance, the approval process at the municipal level, though vetted through staff and adhering to local bylaws and policies, remains a largely political process. Cities have been challenged by the ability to accurately predict the best uses in zoning and therefore often create large "blanket" zones which require the involvement of the elected government to change.

Official community plans as contemplated under the *Local Government Act* forecast future land uses, but do not always reflect the desired land use for property. For example, a utility structure may pre-date the zoning bylaw or even the creation of the municipality but is often not identified in the official community plan for appropriate future zoning. What should be simply a "housekeeping" change to the zoning bylaw to accurately reflect the existing use of a property becomes an application requiring majority vote of Council to amend the official community plan, allowing a host of referral mechanisms to influence the approval process.

Land use designations in rural areas and between rural/urban interfaces prove to be particularly challenging when predicting appropriate future land use. Rather than being committed to a particular use, most land situated in these interface areas is only broadly reviewed during the preparation of an Official Community Plan. Historical uses, while grandfathered and not subject to new bylaws or regulations, may become controversial as the urban/suburban realm encroaches into what were once rural and only moderately populated areas. Existing uses, such as agricultural, utility and industrial uses that were suitable for the outskirts of a municipality are encroached upon by growth and are more visible and prominent. Proposed changes to an existing use often trigger difficult political and public engagement processes.

In addition to the political structure which encourages public involvement in making land use decisions, the advancement of technology over the last five years has allowed much greater mobilization of interest groups. The proliferation and accessibility of communications technology, including internet and social networking sites, has revolutionized the dissemination of information. Mobilizing the public is easier with these increased technological advances, and continues to be a means that is both a benefit and a detriment to the public process.

FortisBC recognizes and is sensitive to the fact that the Company's infrastructure may have public impacts. While public participation has played an important role in shaping communities, the additional public consultation sessions has resulted in lengthened project timelines.

5. PUBLIC AND FIRST NATIONS CONSULTATION

5.1 Public Consultation

FortisBC engaged in public consultation for the development of this Integrated System Plan to ensure that interested residents, government and business stakeholders were provided with an opportunity to learn about, and provide input into, the Integrated System Plan. Activities included face to face meetings, four public open-house meetings, six government meetings and two facilitated Super Groups (focus groups). The public consultation process was advertised on the FortisBC website and in local news media across the FortisBC service territory. Stakeholders and First Nations were also individually notified. First Nation consultation, other than notification of the public open houses and an offer to present to Councils, took place in a separate process and is discussed in Section 5.2.

Open houses were held in February 2011 in Kelowna, Osoyoos, Creston and Castlegar. Each open house ran from 6:00 p.m. to 8:30 p.m., with scheduled time for a presentation, an opportunity for open house participants to ask questions and then time for participants to visit information stations staffed by FortisBC representatives. Each station outlined information on one topic and provided graphic display panels. Topics included general information (2012 ISP and regulatory process), resource planning (planning margin and supply options), demand side management and advanced metering infrastructure, capital projects (proposed projects, customer priorities and environmental and social consideration fund), asset management and generation. Of the 54 people that signed in at the open houses 39 returned exit surveys. A further four written submissions were also provided to FortisBC.

All open house material including a copy of the presentation, graphic information panels, the exit survey and a video recording of the presentation were also included on the FortisBC website for those that could not attend an open house in person.

In order to gather additional feedback and to ensure input from a representative sample of FortisBC customer groups, FortisBC hired Illumina Research Partners (formerly Environics Research Group) to conduct two Super Groups – one in Kelowna and one in Castlegar. In each case a representative sample of customer groups (residential, general service, industrial, irrigation and lighting) was randomly selected. A total of 56 people participated in Kelowna and 59 in Castlegar. In-depth surveys were completed by all of the Super Group participants.

Lastly, FortisBC sent invitations for the open houses with an offer to present to each of the local governments, Members of the Legislative Assembly, Members of Parliament, Bands and Nations within the FortisBC service territory. Five local governments including the City of Kelowna, City of Trail, District of Summerland, Town of Princeton and Regional District of Okanagan Similkameen requested and received presentations. Additionally, elected officials and representatives from local government attended at all four of the open houses. FortisBC staff also met with Katrine Conroy, MLA West Kootenay Boundary.

5.2 First Nations Consultation

In addition to notifying First Nations of the public consultation sessions, the Company has provided the First Nations with a summary document describing the 2012 ISP, and has offered to make presentations at upcoming Council meeting. To date no material concerns have been relayed. The Company has requested written feedback by September 30, 2012 and will provide a written summary of any feedback received.

5.3 Consultation Findings

The most comprehensive feedback was provided through the Super Groups, which collected input from a representative sample of customer classes and solicited more in-depth feedback from a greater number of individuals. In general, feedback from the open houses and government meetings was similar in character.

Super Group overall perceptions of 2012 ISP:

- 75 percent strongly or somewhat agreed that the 2012 ISP fulfills the objective of planning for electrical needs over the next 20 to 30 years;
- 94 percent strongly or somewhat agreed that FortisBC's presentation helped them understand the 2012 ISP better; and
- 83 percent strongly or somewhat agreed that FortisBC's presentation provided a balanced perspective on the 2012 ISP;

Conservation / Demand Side Management

- Almost three quarters of customers identified conserving energy /reducing energy consumption (73 percent) and helping customers manage consumption (72 percent) as critically important challenges for planning for future energy and infrastructure needs.

Rates

- Electrical rate increases are a concern across all potential 2012 ISP related initiatives. Kootenay participants are more price sensitive and consequently, they are less willing to accept rate increases for 2012 ISP initiatives.

Resource Planning

- 96 percent of customers support the Planning Reserve Margin with 60 percent willing to pay higher rates for the Planning Reserve Margin; and
- 75 percent support the use of contractual agreements to fill small gaps in short term energy supply rather than building new generation resources.

Social and Environmental Considerations

- 89 percent say social and environmental components such as visual screening, special environmental treatment or other community specific amenities should be considered when determining future capital project budgets. Only 50 percent of these respondents are willing to pay higher rates for these components; and
- Over half of participants saw one percent as a reasonable amount to add to the capital project budgets for social and environmental considerations.

Asset Management

- 92 percent of respondents support the change from time-based to condition-based management.

Advanced Metering Infrastructure

- While a large number of participants selected having in-home displays provided as part of the AMI project, some hedged their selection with comments like only if there is no additional cost or if it does not increase electricity rates; and
- If in-home displays are optional, most customers would pay up to $50.00 for the technology.

The Integrated System Plan Public Consultation Report provided as Appendix K of the 2012 Long Term Capital Expenditure Plan more fully describes the consultation process and results.

2012 Integrated System Plan
(2012 ISP)

Volume 1

2012 Long Term Capital Plan

June 30, 2011

FortisBC Inc.

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1. FORTISBC 2012 LONG TERM CAPITAL PLAN

The 2012 Long Term Capital Plan outlines projects forecast to be required over the next 20 years (30 years in the case of bulk transmission projects). The 2012 Long Term Capital Plan is a comprehensive plan, in which the Company will describe its long term strategic plan for management of the full range of its infrastructure and assets, including generation, transmission, and distribution, in order that it will continue to provide safe, reliable power to its customers over the course of the next two to three decades.

Additionally, the 2012 Long Term Capital Plan incorporates shorter term action plans necessary to ensure that the longer term strategy remains viable. Therefore, included in the 2012 Long Term Capital Plan is information for the short term (2012-2013), medium term (2014-2016) and long term (2017 onward).

The Company is not seeking Commission approval of specific projects and associated expenditures discussed in the 2012 Long Term Capital Plan. Rather, as stated in Section 8 of the Application, the Company is seeking Commission's acceptance of its Integrated System Plan, of which this Long Term Capital Plan is part, to be in the public interest under Section 44.1(6) of the *Utilities Commission Act*. The Long Term Capital Plan, together with the Long Term Resource Plan and Long Term DSM Plan, provide the contextual framework for the Company's 2012 - 2013 Revenue Requirements and 2012-2013 Capital Expenditure Plan applications. As it has done previously, the Company expects to review the Long Term Capital Expenditure Plan in conjunction with subsequent Capital Expenditure Plans and to prepare and file updates and seek specific Commission approval as appropriate.

1.1 Asset Management

Since 2005, FortisBC has invested approximately $700 million in new or upgraded generation, transmission/distribution and general plant infrastructure. Much of the transmission and distribution networks infrastructure, in particular, was being driven by customer and associated load growth.

FortisBC's future capital investments will continue to focus on the efficient management of its generating, networks and other infrastructure. This section describes the Company's progress towards a more mature and effective Asset Management focus.

An Asset Management strategy assists in making optimal maintenance and capital investment decisions measured against performance targets and financial constraints. The desired outcome is that all stakeholders have full knowledge of what planned projects should deliver, the risk versus cost tradeoffs between available options, and the costs and risks of not meeting performance targets.

A commonly-used benchmark for utility asset management is the “PAS 55 - Optimal Management of Physical Assets” standard. This publicly-available specification, developed by the British Standards Institute, provides guidance and best practices for asset management in utility, transportation and manufacturing industries. The following high-level statement from PAS 55 describes “Asset Management” as:

> *“Systematic and coordinated activities and practices through which an organization optimally manages its assets, and their associated performance, risks and expenditures over their lifecycle for the purpose of achieving its organizational strategic plan.”*

Some of the tangible benefits of a formal Asset Management strategy are:

- Provides regulatory and corporate confidence that investment levels match the needs of the system without going further than necessary;
- Provides confidence that appropriate mechanisms are in place to manage assets and provide the best value to customers;
- Ensures that risk is being managed appropriately;
- Establishes a long-term view of infrastructure investment;
- Objectively establishes a view of asset health and identifies necessary investments;
- Ensures the organization consistently carries out work to a recognized standard and that there is consistency in approach; and
- Reduces the reliance on individual experts and instead builds overall corporate knowledge.

As FortisBC transitions from a period of necessary capital investment in the system to a larger focus on sustainment, it is important to consider the balance the Company must maintain between reliability, safety, and cost. There is a need for newer methodologies to maintain this balance, which FortisBC believes can best be met by building on the investments made in the system over the past number of years, and leveraging evolving technologies which will allow it to continue to maintain this ever finer balance.

FortisBC has been moving toward a condition-based Asset Management approach for a number of years, however this transition and the philosophy has not been fully developed and implemented as yet. Primarily this is due to the fact that the large amount of growth driven capital investment over the preceding six years has taken priority over the development of a formal Asset Management strategy. As the Company transitions towards a focus on sustainment levels of capital expenditures, it is felt that the timing is appropriate to move towards an Asset Management model. A fully developed Asset Management solution will improve the ability of the Company to present objective and prudent investment decisions for the benefit of customers.

1.1.1 HOW FORTISBC MANAGES ASSETS TODAY

FortisBC manages its assets through a variety of processes and uses both time and condition-assessment criteria to determine the health and condition of its plant. This information is used to make decisions both for the scheduling of maintenance tasks and capital asset replacement projects.

Generation

FortisBC operates and maintains four generating facilities with a total of 15 units. Historically, time based scheduling has been used to trigger equipment maintenance and replacement. This was appropriate for the installed equipment which provided little feedback in the way of equipment monitoring or status. In order to maximize the efficiency with which this time based maintenance was performed, a Computerized Maintenance Management System (CMMS) was developed to track and schedule work orders. Currently, minimal information is tracked with respect to direct health of equipment and thus asset condition information is not generally used for scheduling of maintenance activities. With the investment in the Upgrade and Life Extension (ULE) program, the Company has replaced many pieces of its legacy equipment, which presents an opportunity to leverage some of the newly installed technology to aid in future maintenance decisions.

Transmission and Distribution - Substations

FortisBC substation asset management has been driven by a combination of time-based and condition assessed scheduling. The Company has been moving towards a more comprehensive condition-based approach for the last several years, however this transition and philosophy has not been fully implemented yet. The development and installation of a substation CMMS was approved by Commission Order G-52-05. This system tracks basic equipment data and condition information for FortisBC's substation assets and is used to assist in scheduling maintenance tasks and sustainment projects.

Transmission and Distribution - Poles and Wires

The sustainment and replacement activities for the poles and wires plant are driven largely by a condition-based philosophy as determined by an eight-year cycle of condition assessments. Every transmission and distribution pole is visited once every eight years to determine the condition of the pole and its attached equipment (conductors, insulators, cross-arms, etc.). If an issue is detected, then the deficiency is documented and corrected either as an urgent or future replacement activity. The information collected is currently not captured in a formal CMMS. Future year sustainment budgets are developed based on the condition assessments that occurred in previous years. Cost forecasts are based on an assumption/extrapolation of historical costs from recent years' actual costs. Due to regulatory filing schedules, complete information on recently completed projects is often not available during the development of future capital plan submissions.

General Plant

This area of the business includes a diverse number of business units such as Vehicles, Information Technology, Facilities, and Metering. Each of these departments develops its own sustainment and replacement strategy appropriate for the assets under its control. Generally, a combination of time-based and condition-based indicators is employed.

As demonstrated above, FortisBC does not currently have a single Asset Management tracking system which can be used to compare and assess the relative health of equipment across different business areas. The Company believes that development of an Asset Management strategy will provide tangible benefits as earlier described.

1.1.2 ASSET MANAGEMENT DEVELOPMENT AND TRANSITION

Through an Expression of Interest, FortisBC has sought advice from several engineering and management consulting companies with experience in implementing Asset Management strategies. Responses were received from six organizations. Not all of the respondents provided estimates of cost and timelines and of those who did, a wide range of costs, timelines and detail was presented. Some of the respondents have significant experience with strategies and tools that have been implemented in electric utilities across

Canada. In at least one instance a full system implementation has been endorsed by the BCUC for another provincial electric utility.

In all cases the consultants advised a staged approach to this initiative. The proposals varied significantly and will ultimately depend on the available data and internal effort FortisBC applies to this initiative. Based on this, FortisBC is proposing a measured implementation timeline in the range of five years. This timeline will provide sufficient opportunity to develop the processes, tools and technology, and organizational culture change to transition the organization to a comprehensive Asset Management philosophy. At various stages, external consultants may be engaged to provide specialized expertise and implementation resources.

The wide range of implementation costs in the Expressions of Interest can in part be attributed to inclusion of software and technology in some proposals as opposed to only consulting services in others. Where software/technology solutions are recommended these are stand-alone solutions and are intended to leverage FortisBC's existing CMMS databases and associated system.

With regard to inclusion of General Plant assets (Vehicles, Information Technology, Facilities, Metering, etc.) the general expert recommendation is to exclude these, at least in the initial implementation stages of FortisBC's Asset Management strategy. It is recommended to develop and substantially implement the systems and processes for core business areas such as generation, transmission and distribution first. At a later time when the Asset Management strategy is well established the system may be extended to include these other business areas.

1.1.3 RECOMMENDATIONS

FortisBC is proposing a staged approach to the development of an Asset Management solution. Expenditures of $785,000 in 2012 and 2013 are proposed to accommodate the development of a project team comprising internal and external resources. This project team will examine FortisBC's existing Asset Management processes and provide a comprehensive report and project cost estimate recommending changes and mapping out an implementation plan. The project will also investigate and evaluate available Asset Management software solutions.

The outcome of this project will be a fully-developed business case with a specific Asset Management implementation strategy. Included in the deliverables is the identification of a software solution capable of producing priority-ranked project listings developed from the objective analysis of equipment health and criticality indices.

Implementation of this initiative is consistent with recent Commission requests during Capital Expenditure Plan and CPCN filings to show increasing detail with respect to the health and criticality of equipment and the relative priority of investment decisions. It is anticipated that this asset management strategy will maximize the benefits associated with necessary capital expenditures, thereby ensuring customers continue to receive safe and reliable electrical service at the lowest reasonable cost.

The costs for this initial development phase of asset management are proposed to be captured in a deferred account, as described in the Company's 2012 -2013 Revenue Requirements application (Tab 5, section 5.4.5 xiii).

1.2 Smart Grid

FortisBC's vision of a Smart Grid is to build upon the foundation of existing infrastructure to ensure a safe, reliable, cost-effective and environmentally friendly electrical system which can facilitate active customer participation, meet future demands and support public policies and standards.

Areas of the FortisBC system that are considered to be within the scope of Smart Grid include:

- The delivery infrastructure (e.g. transmission and distribution lines, transformers, switches);
- The end-use customer systems and devices as well as any distributed-energy resources;
- Integrated management and coordination of the electrical infrastructure;
- The communications networks required to support the flow of data; and
- The information systems required to collect, analyze and store Smart Grid data.

Table 1.2 below highlights some key differences between the legacy power system grid of the 20th Century and the possible outcomes of the future Smart Grid.

Table 1.2 - Evolution of the Power System Grid

20th Century Grid	21st Century Smart Grid
Minimal communications capability	Integrated two-way communications between the customer and the utility
Customer cost/consumption feedback provided after-the-fact through bills only	Customer cost/consumption feedback provided near real-time and via multiple choices
No customer outage detection (customer must call in)	Automated outage detection and notification
Limited ability to support conservation rates	Full ability to support multiple types and complex conservation rates
No tamper detection capability	Automated meter tamper alarms, support for theft detection strategies
Designed for unidirectional power flow from centralized generation to the customer	Accommodates distributed generation and bidirectional power flow
Few sensors to provide information on system status	Self-monitoring with sensors throughout
Manual restoration	Semi-automated restoration and eventually self-healing
Few consumer choices	Many consumer choices

In order to facilitate comparison with other utilities in North America, FortisBC intends to use the “Smart Grid Characteristics” defined by the United States Department of Energy. In the coming years, funding recipients in the United States will use these defined categories to present plans and progress. These characteristics are:

- Enables Informed Participation by Customers;
- Accommodates All Generation and Storage Options;
- Enables New Products, Services, and Markets;
- Provides the Power Quality for the Range of Needs;
- Optimizes Asset Utilization and Operating Efficiency; and
- Operates Resiliently to Disturbances, Attacks and Natural Disasters.

FortisBC already has a demonstrated record of implementing Smart Grid technology when it is in the customers’ interest. An example is the Distribution Substation Automation Program which involves upgrading the protection, control, metering and communications systems at 32 of the Company’s distribution substations. This project, which is scheduled for completion by the end of 2011, meets many of the goals of the Smart Grid described above. Another example is the Advanced Metering Infrastructure (AMI) deployment described in section 5.5.

This project will improve operating efficiency, reduce operating costs and enhance customers' ability to interact with the utility. It is a fundamental cornerstone which will enable future technologies and innovation that will ultimately lead to a smarter grid.

Predicting the uptake of new technologies such as electric vehicles and distributed generation is very difficult at this time. To date, the Company has seen only limited customer interest; however, this may change as the cost of current energy sources continues to increase.

FortisBC is considering Smart Grid applications as part of its Advanced Metering Infrastructure (AMI) program. One example of a Smart Grid application which FortisBC is evaluating is Conservation Voltage Reduction (CVR) which is also referred to as Voltage and Var Optimization (VVO). CVR is method of reducing energy consumption by reducing distribution feeder voltage. Electric utilities historically have designed and operated substation and feeder equipment to supply the minimum acceptable voltage to customers at the time of the system peak (i.e. during worst-case conditions). At all other times the distribution voltage may be operating at a higher voltage than necessary and thus resulting in increased customer energy consumption and system losses. CVR uses integrated technologies such as AMI, distribution Smart Grid devices and substation voltage regulators, managed by automating software to deliver the lowest necessary voltage to customers at all times. This voltage optimization results in reduced energy consumption by customer loads and thus reduced demand on the utility system. FortisBC is continuing to investigate this technology and further details of the potential costs and benefits of CVR will be presented in the 2011 application for a Certification of Public Convenience and Necessity (CPCN) for the AMI project.

Going forward, the development and implementation of future Smart Grid projects and components will be business-case driven to ensure cost-effective planning.

2. SYSTEM DEVELOPMENT PLANNING

To assist in optimal decision making for capital investments, FortisBC periodically undertakes the development of long-term capital plans. The planning process is complex and dynamic; this section describes major inputs to the planning process, including load forecasts, cost estimation and capital-related accounting practices.

2.1 Load Forecasting

Load forecasting is essential for capacity, contingency planning and system upgrades. Planning, designing, building transmission and distribution infrastructure can take from a couple of years up to 25 years. For efficient and effective infrastructure upgrades it is necessary to understand how load may grow in the future.

For capital planning purposes, a substation level load forecast is produced from the "bottom up" (i.e. from the distribution feeder level). The substation load forecast attempts to account for expected weather extremes which directly impact winter and summer peak loads. It is a non-coincidental peak load forecast used to determine the substation, distribution and transmission infrastructure needed in order to supply all FortisBC customers during peak demand periods and adverse weather conditions.

Distribution planning involves both capacity and contingency planning. Capacity planning ensures that the power distribution system will not be overloaded by ensuring it has sufficient conductor size for projected load levels, and by ensuring the voltage is sufficient at all points for all of the feeders. Contingency planning ensures that load can be adequately served when a transformer or a substation fails.

In preparing the Distribution Load Forecast (found at Appendix B), Load is forecast first at the distribution feeder level, then built up to the transformer level using historical coincident factors. Where appropriate, the Distribution Load Forecast is adjusted to reflect information available through the relevant official community plans and through ongoing discussions with regional or municipal planners and local developers.

The forecast regional load growth rate is determined from trends of historical regional load data, adjusted to the system load growth. It takes account of highly probable load developments, such as community developments that have an expected online date and defined load, and feeder switching to transfer from one facility to another to off-load a feeder or transformer in a certain year.

Transmission planning studies require a load forecast having a quantitative risk index in order to achieve consistency with industry practice and established reliability standards. To this end the Company provides a "1-in-20" load forecast, which produces forecast peak loads that are expected to be higher than the actual peak loads in 19 out of 20 years. Its success rate is therefore expected to be 95 percent. The "1-in-20" winter and summer peak demand forecasts for the period 2011-2040 is included in Appendix B. These methodologies are described in the Load Forecast documentation in the Company's 2012 - 2013 Revenue Requirements application (Tab 3).

The FortisBC transmission planning group also uses data from both the total system load forecast (which is a "top down" forecast, used to determine FortisBC expected resource requirements on a monthly and annual basis) and the aggregated distribution and regional load forecasts to develop forecast loads allocated to FortisBC busses on the Western Electricity Coordinating Council (WECC) power flow model. This data is submitted to the WECC annually for application in regional and system-wide transmission planning studies.

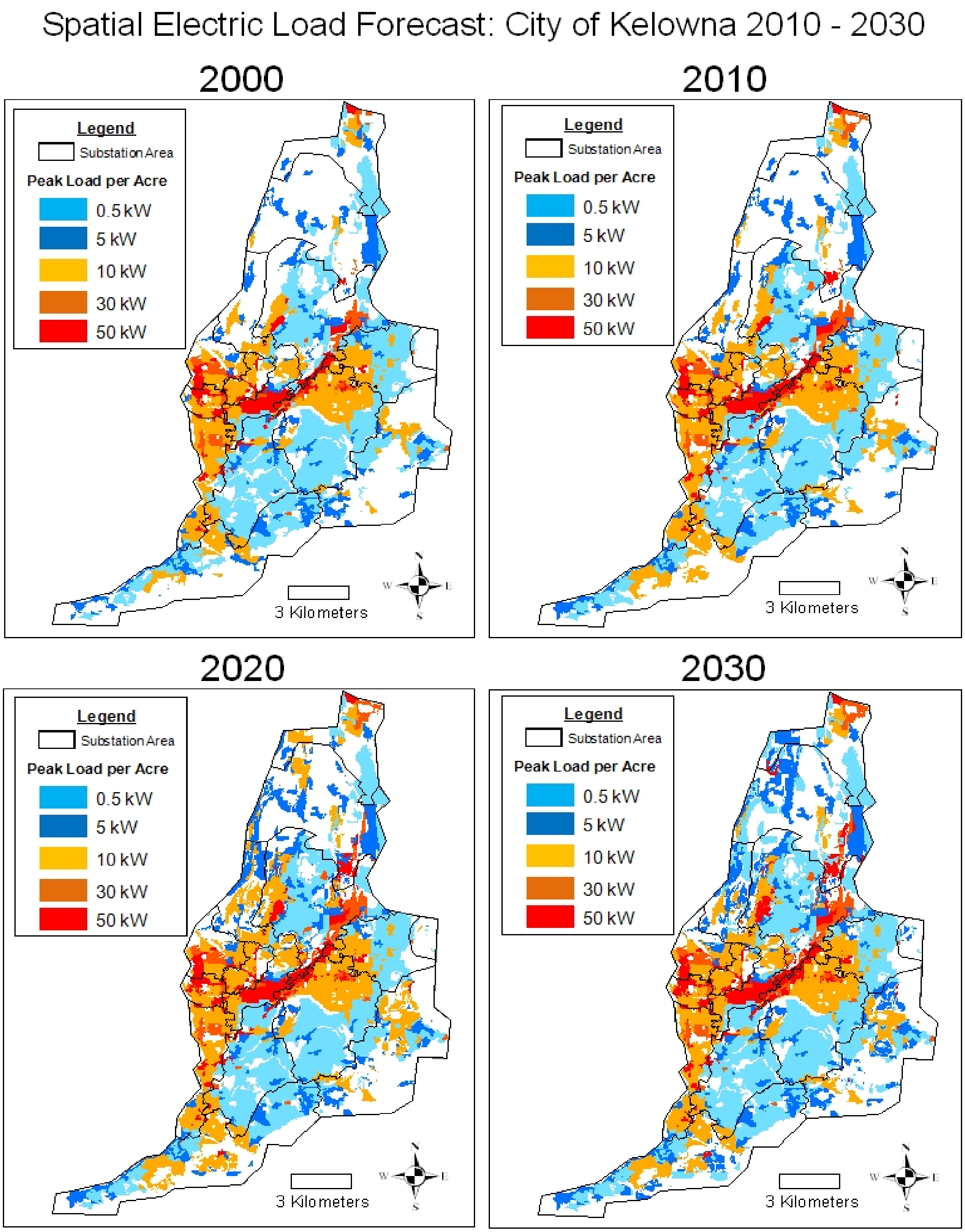
2.1.1 KELOWNA AREA SPATIAL LOAD FORECAST

Spatial Electric Load Forecasting is a process of predicting future electrical loads in a localized area, and can be applied to each customer group at a detailed geographic level. These load densities, combined with the future land use maps, create a forecast peak load map. This can be overlaid with substation or feeder polygons to determine a feeder-by-feeder forecast in a tabulated format.

FortisBC engaged an engineering consultant to develop a spatial electric load forecast for the Kelowna area. A report on the methodology and results is included in Appendix C - Spatial Electric Load Forecasting, Kelowna, BC.

Results to date have provided meaningful information of urban expansion patterns in the Kelowna area, as shown in Figure 2.1.1. Increasing peak load per acre is visible over the 2000-2030 timeframe. Combined with projected load growth rates by feeder, also obtained through the spatial load forecasting method, this knowledge will be applied to gain better definitions of feeder and substation upgrades, as well as best locations for new substations and feeders.

Figure 2.1.1 - Kelowna Area Historical and Projected Load Densities



The Company believes that this methodology has good potential to improve future forecasting efforts, and should be further enhanced and developed to obtain increasingly better results and planning insight. Some areas of enhancement that may be undertaken in the future include:

- Expanding forecasting area to the entire FortisBC region;
- More detailed feeder and substation regression trending to guide the model;
- Determining better growth rates on a per customer class basis; and
- Expanding on the land use classifications.

2.2 Project Estimation Methodology

In preparing the estimates for the plan, concepts developed by the Association for the Advancement of Cost Engineering (AACE) were introduced. FortisBC referenced a number of documents in developing improved internal estimating practices, including the:

- AACE International Recommended Practice No. 10S-90, "Cost Engineering Terminology";
- AACE International Recommended Practice No. 17R-97 "Cost Estimate Classification System"; and
- AACE International Recommended Practice No. 18R-97 "Cost Estimate Classification System - As Applied in Engineering, Procurement, and Construction for the Process Industries".

The AACE 18R-97 document is specifically structured for process industries including firms involved with the manufacturing and production of chemicals, petrochemicals, and hydrocarbon processing. However, the guidelines are generally applicable to other industries, which could include regulated utilities. Specific guidelines addressing other industries (such as utilities) may be developed by AACE over time.

In Order G-50-10 and its associated document entitled "2010 Certificates of Public Convenience and Necessity - Application Guidelines", the Commission has already required the use of the AACE estimating classifications in the development of Certificate of Public Convenience and Necessity (CPCN) cost estimates. For example, Class 4 level estimates are required for CPCN project option analysis estimates and Class 3 level estimates are required for the recommended project solution.

FortisBC has extended this concept beyond CPCN applications and has employed the AACE concepts during the scoping and estimating of the projects in the 2012 System Development Plan. In reviewing and evaluating the AACE guidelines, the company developed the following structured approach to cost estimating as it relates to the guideline.

Table 2.2 - AACE Classifications

AACE Classification	Project Stage	Description	FortisBC Typical Project Plan Windows
Class 5	Identify	Determine project feasibility and alignment with business strategy.	5 to 20 year plan window
Class 4	Evaluate	Select the preferred Development Option(s) and Execution Strategy.	3 to 5 year plan window
Class 3	Define	Finalize project scope, cost and schedule and Sanction Project. Prepare for Execute Phase.	1 to 2 year plan window (Capital Plan approval window)
Class 2	Execute	Safely Produce an operating asset consistent with scope, cost and schedule.	Tracking execution
Class 1	Operate (or Audit level)	Evaluate and Operate asset to ensure performance to specifications and maximum return to the Client.	Quality Control or Close Out

It should be noted however that the AACE classification approach is still under development; therefore, not all capital projects can be categorized as the above table suggests. For example, sustainment programs such as the Transmission/Distribution Rehabilitation programs do not have sufficient information available at the time the plan is prepared to develop full Class 3 accuracy estimates and supporting documentation.

As well, the AACE classifications and guidelines were generally intended for private industry. As a regulated utility with an obligation to serve safely and reliably, FortisBC does not necessarily have the same freedom of scope and cost control in its projects.

All project cost estimates were developed in 2010 dollars and include an annualized, constant 2 percent inflation rate based on the Consumer Price Index (CPI).

2.2.1 ACCOUNTING PRACTICES

FortisBC's Capitalization Policy guidelines currently conform to *Pre-Changeover Canadian Generally Accepted Accounting Principles* (CGAAP) and US Generally Acceptable Accounting Principles (US GAAP). Pre-changeover CGAAP is the basis for the preparation of the Company's regulatory filings through 2011. However beginning in 2012 these standards will be withdrawn by Canadian standard setters and will cease to exist as a financial reporting option. This leaves two available options for FortisBC to prepare its regulatory filings beginning in 2012 and onwards; US Generally Acceptable Accounting Principles (US GAAP) or International Financial Reporting Standards (IFRS).

While the BCUC has not yet approved FortisBC to adopt US GAAP for regulatory purposes, the Capitalization Policy under pre-changeover CGAAP is generally consistent with and permitted under US GAAP, particularly if the policy receives regulatory approval. In the event that FortisBC is ordered to implement accounting policies other than US GAAP for 2012, the Capitalization Policy may result in changes. A further discussion on changes to accounting standards and policies can be found in the 2012 - 2013 Revenue Requirements application.

By way of Order G-195-10, the Commission directed certain expenditures to be classified as Operating and Maintenance Expense, and further (Directive 16) required the Company to prepare a report addressing aspects of its Capitalization Policy, with specific reference to Transmission and Distribution Capital Sustainment programs. This report is found at Appendix M of the 2012-2013 Revenue Requirements.

Project costs include direct and indirect (overhead) costs. Projects are allocated a proportion of indirect costs, including corporate overheads, using the principles of activity-based costing. The Company's Capitalized Overhead Policy is described in the 2012 - 2013 Revenue Requirements Application (Tab 4, section 4.4).

2.2.2 COSTS OF REMOVAL

Consistent with Canadian rate-regulated utility industry practice, FortisBC incurs costs of removal, sometimes referred to as negative salvage, that are integral to executing its capital expenditure plan and providing safe and reliable electricity to its customers. Since utility assets are normally replaced or upgraded before they fail, removal and disposal costs are required to be incurred at the end of the useful life of a long-lived capital asset that has been placed into service. There are also instances when costs of removal must be incurred when an item of plant suddenly fails. Costs of removal are prudent and necessary costs to be incurred as part of providing service to customers and should hence are be recoverable from the users of the system and infrastructure. The forecast amounts reflect the expected expenditures of removing existing infrastructure less any salvage credits for scrap material sold or returned to inventory for reuse.

Cost of removal forecasts are established, where applicable, for individual projects included in (1) generation, (2) transmission and distribution and (3) general plant, as described in the following sections.

(1) Generation costs of removal

Generation capital projects, including upgrades and ULE programs, have a cost of removal component when existing equipment is removed from service or projects replace equipment which has reached the end of life. The cost to remove components such as old trash racks, generators, turbines, tailrace gates, concrete and structural steel from plant in-service is estimated based on historical actual costs to remove similar assets, adjusted for current pricing. These costs are an integral part of the scope of work and the costs are comprised of estimated material, labour, supervision and contractor costs to complete the removal.

(2) Transmission and Distribution costs of removal

For distribution and transmission rehabilitation and rebuild projects, the work is quite similar from an installation and removal standpoint, for example, a new pole or structure is to be installed where an existing one is to be removed. In most cases this involves the moving of the existing facility enough to put the new facility in and then the removal of the old pole or structure. The work to install the new structure as well as part of the alteration to stand off existing facilities to safely place the new structure is considered new construction. Part of the alteration as well as the removal of the old facility is considered cost of removal.

In estimating the cost of removal component for transmission rehabilitation, distribution rehabilitation, rebuilds and small planned capital projects, the Company applies a ratio of 30 percent to engineering, project management, supervision, construction labour and vehicles charges to the salvage of facilities.

For transmission and distribution Urgent Repair projects, a ratio of 50 percent of these components is used since these are typically short duration projects where a crew is called to replace damaged and failed facilities.

Materials, land, and brushing are not considered to have a cost of removal component.

(3) General Plant costs of removal

General plant costs of removal primarily relate to information systems and facilities projects. Information system projects estimate a cost of removal component when equipment reaches the end of its useful life. These estimates include the costs to transfer and remove data from retired servers, printers and personal computers to ensure that data can't be recovered once the equipment is disposed of or recycled. There is also a cost of removal associated with transportation handling and disposal fees to retire equipment. Facilities projects have a cost of removal component related to the disposal of material in the case of renovations. Costs include the handling, transportation and disposal fees associated with the old material.

Project costs in this Long Term Capital Plan are presented inclusive of costs of removal.

2.3 FortisBC System Description

FortisBC is focused on the safe delivery of reliable and cost-effective electricity to approximately 161,000 customers severed directly and indirectly through wholesale utilities in the southern interior of British Columbia.

With over 500 employees, FortisBC owns and operates four hydroelectric generating plants on Kootenay River between Castlegar and Nelson and has approximately 7,000 kilometres of transmission and distribution power lines.

The transmission and distribution projects are summarized below as they occur by geographic regions. FortisBC's generating plants are located in the Kootenay region. For the purpose of these summaries the FortisBC service territory has been divided into North Okanagan, South Okanagan, Kootenay and Boundary regions.

Tables 2.3 (a), 2.3 (b), and 2.3 (c) below provide some useful comparisons between the regions including customer counts and transmission and distribution line lengths in kilometres, as well as future expenditures.

Table 2.3 (a) - Customer Counts per Region

Region	Direct Customers	Indirect Customers	Total Customers
North Okanagan	48,915	14,289	63,204
South Okanagan	24,804	22,488	47,292
Kootenay	32,567	9,869	42,436
Boundary	6,332	2,123	8,455
FortisBC	112,618	48,769	161,387

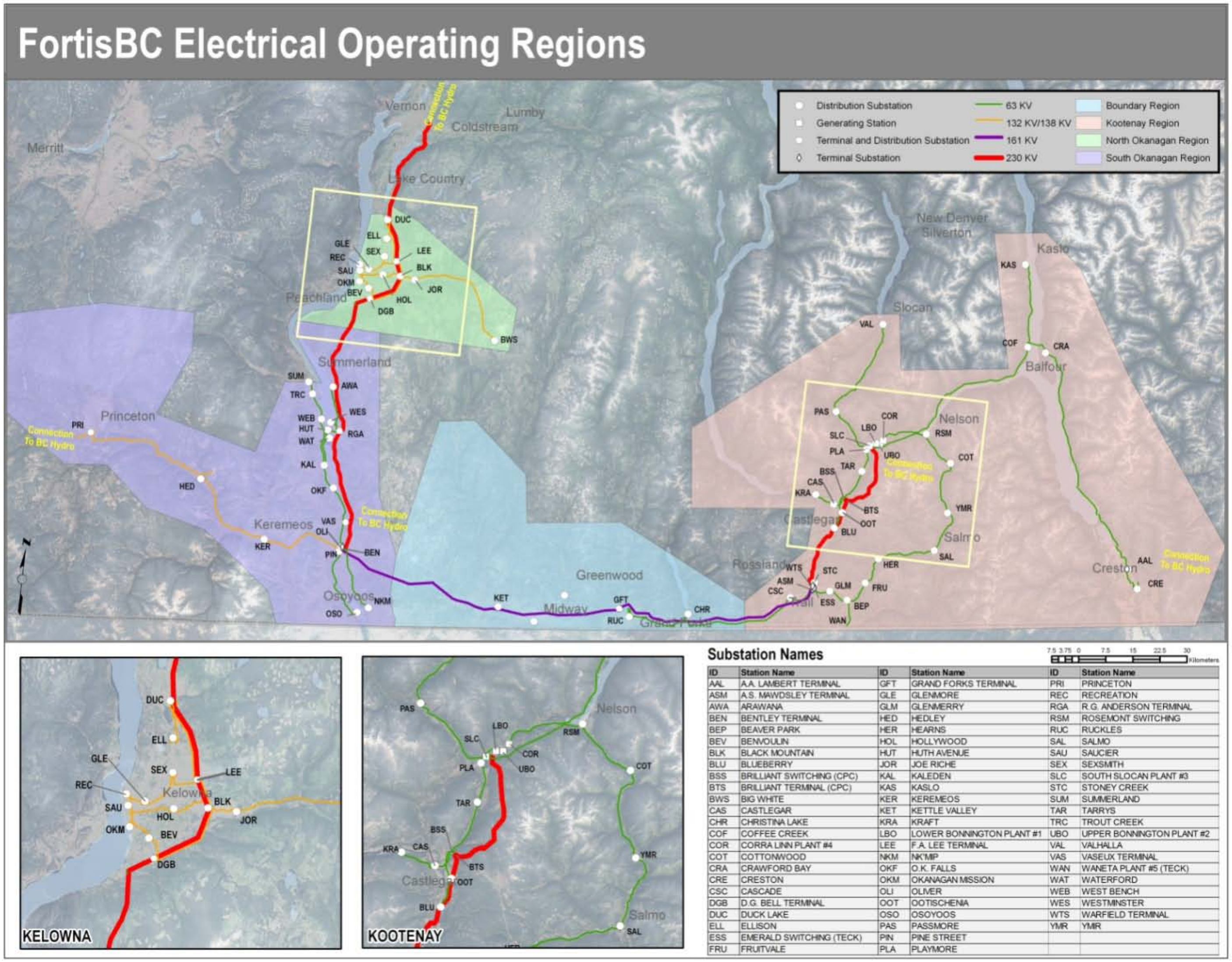
1 **Table 2.3 (b) - Transmission and Distribution Line Lengths per Region**

Region	Transmission	Distribution	Total
	(kilometres)		
North Okanagan	230	1,243	1,473
South Okanagan	355	1,667	2,022
Kootenay	539	1,846	2,385
Boundary	266	848	1,114
Total	1,390	5,604	6,994

2 **Table 2.3 (c) - Capital Expenditure Plan Summary**

		2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Generation	10,131	2,947	11,696	4,433	5,019	233,690
2	Transmission and Stations	35,254	32,854	32,024	38,385	30,220	550,714
3	Distribution	29,249	25,889	29,351	27,537	32,878	526,127
4	Telecom SCADA Protection and Control	2,329	3,682	2,661	9,768	5,957	53,815
5	General Plant	23,093	57,800	19,920	9,423	9,885	193,974
6	**Total**	**100,057**	**123,172**	**95,653**	**84,796**	**83,959**	**1,559,120**

1 **Figure 2.3 (a) - FortisBC Electrical Operating Regions**

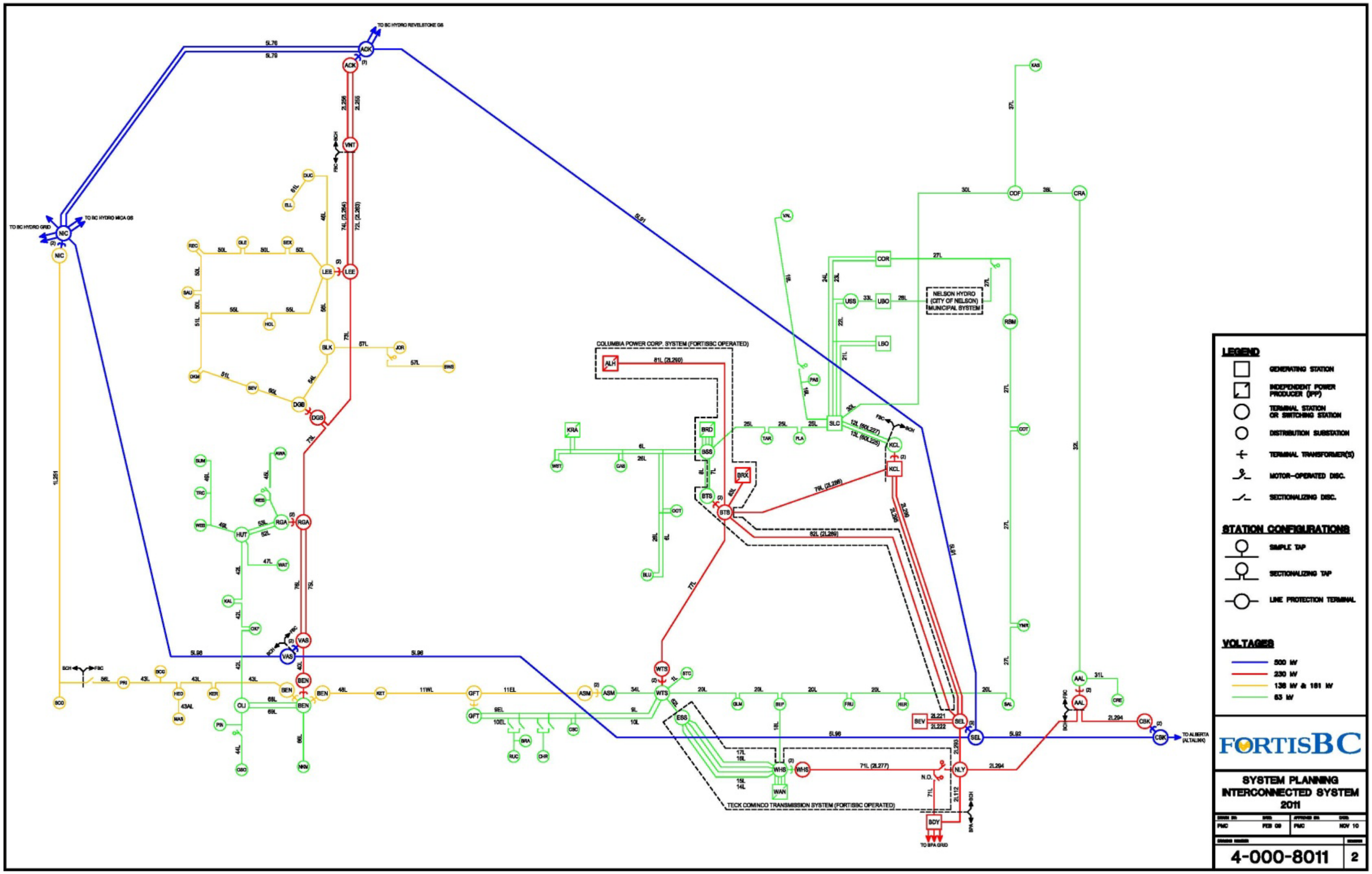


Substation Names

ID	Station Name	ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	GFT	GRAND FORKS TERMINAL	PRI	PRINCETON
ASM	A.S. MAWDSLEY TERMINAL	GLE	GLENMORE	REC	RECREATION
AWA	ARAWANA	GLM	GLENMERRY	RGA	R.G. ANDERSON TERMINAL
BEN	BENTLEY TERMINAL	HED	HEDLEY	RSM	ROSEMONT SWITCHING
BEP	BEAVER PARK	HER	HEARNS	RUC	RUCKLES
BEV	BENVOULIN	HOL	HOLLYWOOD	SAL	SALMO
BLK	BLACK MOUNTAIN	HUT	HUTH AVENUE	SAU	SAUCIER
BLU	BLUEBERRY	JOR	JOE RICHE	SEX	SEXSMITH
BSS	BRILLIANT SWITCHING (CPC)	KAL	KALEDEN	SLC	SOUTH SLOCAN PLANT #3
BTS	BRILLIANT TERMINAL (CPC)	KAS	KASLO	STC	STONEY CREEK
BWS	BIG WHITE	KER	KEREMEOS	SUM	SUMMERLAND
CAS	CASTLEGAR	KET	KETTLE VALLEY	TAR	TARRYS
CHR	CHRISTINA LAKE	KRA	KRAFT	TRC	TROUT CREEK
COF	COFFEE CREEK	LBO	LOWER BONNINGTON PLANT #1	UBO	UPPER BONNINGTON PLANT #2
COR	CORRA LINN PLANT #4	LEE	F.A. LEE TERMINAL	VAL	VALHALLA
COT	COTTONWOOD	NKM	NK'MIP	VAS	VASEUX TERMINAL
CRA	CRAWFORD BAY	OKF	O.K. FALLS	WAN	WANETA PLANT #5 (TECK)
CRE	CRESTON	OKM	OKANAGAN MISSION	WAT	WATERFORD
CSC	CASCADE	OLI	OLIVER	WEB	WEST BENCH
DGB	D.G. BELL TERMINAL	OOT	OOTISCHENIA	WES	WESTMINSTER
DUC	DUCK LAKE	OSO	OSOYOOS	WTS	WARFIELD TERMINAL
ELL	ELLISON	PAS	PASSMORE	YMR	YMIR
ESS	EMERALD SWITCHING (TECK)	PIN	PINE STREET		
FRU	FRUITVALE	PLA	PLAYMORE		

3 This figure is also available in a larger size at Appendix C-1.

Figure 2.3 (b) - FortisBC Single Line Diagram



This Figure is also available in a larger size at Appendix C-2.

2.3.1 NORTH OKANAGAN REGION

Characteristics

FortisBC's North Okanagan region includes the City of Kelowna and surrounding areas including Winfield to the north and Joe Rich and Big White Ski Resort to the east.

Kelowna is the largest city within the FortisBC service territory and also has the highest load concentration. Compared to other FortisBC regions, the North Okanagan covers a relatively small geographic area, but it accounts for over one third of the total FortisBC system load; the region contains nearly 40 percent of the total 161,000 customers that FortisBC serves directly and indirectly.

The North Okanagan region also includes the municipal electrical utility owned by the City of Kelowna, one of five municipal utilities within the FortisBC service territory. FortisBC operates the municipal utility under contract to the City of Kelowna. The municipal utility has approximately 14,300 customers, which are indirectly served by FortisBC. There are also approximately 48,900 direct customers, for a total of 63,200 customers in the North Okanagan region.

Operations

Operations in the North Okanagan region are distinct from other regions in the FortisBC service territory because of its primarily urban nature. The driving time from the FortisBC operations centre to any location within the North Okanagan region (with the exception of Big White Ski Resort) is no more than 30 minutes depending on time of day and traffic patterns. Combined with the large number of customers in this area, the resulting customer load density is much higher as compared to the other FortisBC service area regions.

To meet customer growth over the past decade, there has been a significant amount of new and upgraded infrastructure added to the system in the area. This includes both substations and distribution feeder infrastructure. As a result, the assets in this area are highly functional and there are fewer condition-related issues compared to other FortisBC regions.

Operations are also different in the North Okanagan because there is a large amount of underground distribution infrastructure. A significant amount of FortisBC's distribution infrastructure, along with most infrastructure in new development areas, is located underground and is highly interconnected. This impacts both the cost of maintenance and capital upgrades. Distribution system operating procedures are also more complex compared to other areas which have primarily overhead and less interconnected distribution systems.

The corporate head office for FortisBC is located in the Kelowna area and most administrative functions are based at this location. Two other offices are used to house the Okanagan warehouse and Operations centre.

Overall, the challenges in the North Okanagan region exist in meeting growth demands and accommodating complex operating procedures and practices to adapt to the rapidly changing system. Sustainment expenditures for this region tend to be lower relative to other regions due to the generally newer vintage of much of the infrastructure.

Growth and Capital Projects

The North Okanagan region has also experienced the highest percentage load growth within the service area in recent years. The 2006 Census showed Kelowna to be fastest growing area in BC and one of the top 10 in Canada[1]. The City's population grew nearly 11 percent between 2001 and 2006.

A number of capital additions have been required to meet growing demand within this region. This includes the construction of four new distribution substations: Big White, Ellison, Black Mountain, and Benvoulin. Construction of the Big White and Ellison substations also included 34 kilometres of new 138 kV transmission line for the Big White project and 6 kilometres for the Ellison project.

The Duck Lake Substation was also recently expanded with the addition of two distribution transformers to serve BC Hydro customers in the Lake Country area. This has contributed to additional load on the bulk transmission system in Kelowna.

Development is expected to continue in this region for the foreseeable future and despite the downturn in economic activity in the later part of the last decade development and resulting load growth appears to have recovered. Within the North Okanagan region, there are currently a number of large customer developments underway. These include:

- Kelowna General Hospital expansion which will nearly double the existing electric load requirements;

[1] http://www.city.kelowna.bc.ca/CM/Page130.aspx

- Kelowna Airport and the University of British Columbia Okanagan expansions which will be completed in 2011;
- The addition of a sixth commercial tower near the corner of Highway 97 and Spall Road, expected later this year;
- Multiple pumping stations for the Glenmore-Ellison Irrigation District (GEID) in north Kelowna; and
- Numerous new residential subdivisions throughout the City of Kelowna and surrounding area.

A summary of projects proposed in the area shown below in Table 2.3.1.

Table 2.3.1 - North Okanagan Projects

Time Frame	Project	Purpose	Section
2012-2013	Ellison to Sexsmith Transmission Tie	Provide a 138 kV loop into the north Kelowna area to improve reliability.	2.8.2
	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	Reconductor line to allow transfer capability from Sexsmith Feeder 1 and FA Lee Feeder 1 to Ellison Feeder 2. Move normal open point to transfer load.	3.1.5
	Kelowna Bulk Transformer Capacity Addition	Add additional 230/138 kV transformation capacity in Kelowna to adequately supply area load up to 2030.	2.8.4
2014-2016	Hollywood Feeder 5 Upgrades	Upgrade the existing distribution network to transfer as much load as possible off of the FA Lee distribution feeder to delay the need for a distribution source at FA Lee.	3.1.6
	Meshing Kelowna Loop	Mesh the 138 kV transmission system in Kelowna to improve reliability.	2.8.6
2017-2031	FA Lee Distribution Transformer addition	Addition of a distribution transformer at the Kelowna Lee Terminal. This will help reduce the risk of a major outage to the Kelowna area.	2.8.21.1
	DG Bell Fourth Feeder Addition	Build a fourth DG Bell feeder in order to offload the existing overloading DG Bell feeders and provide some backup capability.	3.1.10
	Reconductor 50 Line (Recreation-Saucier substation)	Reconductor Recreation to Saucier section of line to larger conductor to remove the bottle neck of capacity on the line.	2.8.16
	Reconductor 51 Line to 60 Line (Benvoulin to OK Mission substation)	Reconductor both lines 51 Line and 60 Line to a higher rated conductor to provide adequate transmission capacity.	2.8.19

Table 2.3.1 - North Okanagan Projects cont'd

Time Frame	Project	Purpose	Section
2017-2031	Sexsmith Second Transformer Addition	Install more transformation capacity at Sexsmith to offload the existing transformer and continue to provide reliable service.	2.8.21.3
	New Enterprise Substation	Install more transformation capacity at Glenmore to offload the existing transformer and continue to provide reliable service and potentially move the substation.	2.8.21.2
	Saucier Second Transformer Addition	Install more transformation capacity at Sexsmith to offload the existing transformer and continue to provide reliable service.	2.8.21.4
	DG Bell 230 kV Ring Bus	Providing the ring bus and sectionalizing the line will remove the faulted section and the DG Bell transformer will continue to be supplied either from FA Lee or RG Anderson.	2.8.10.2
	DG Bell Static VAR Compensator	Install a +150/-50 MVAR Static VAR Compensator at DG Bell Terminal.	2.8.10.1
	Ellison Second Transformer Addition	Install more transformation capacity at Ellison to offload the existing transformer and continue to provide reliable service.	2.8.21.6
	Benvoulin Second Transformer Addition	Install more transformation capacity at Benvoulin to offload the existing transformer and continue to provide reliable service.	2.8.21.5
	DG Bell Distribution Transformer Addition	Install more transformation capacity at DG Bell to offload the existing transformer and continue to provide reliable service.	2.8.21.7
	Reconductor 50 Line	Reconductor the whole 50 Line to a higher rated conductor. This is second stage of reconductoring of 50 Line.	2.8.16
	DG Bell Second 230/138 kV Transformer	Add a 230/138 kV transformer to DG Bell Terminal and install the required number of 230 kV and 138 kV circuit breakers to connect the new transformer.	2.8.10.3
	Reconductor 54 Line	Reconductor 54 Line to a higher rated conductor to provide adequate transmission capacity.	2.8.20

2.3.2 SOUTH OKANAGAN REGION

Characteristics

The South Okanagan region comprises the following communities: Summerland, Penticton, Okanagan Falls, Kaleden, Naramata, Keremeos, Princeton, Oliver and Osoyoos. Geographically, the South Okanagan region is the second largest area in the FortisBC service territory after the Kootenay / Boundary region.

This region includes two municipal utilities, the City of Penticton and the District of Summerland. The City of Penticton municipal utility has approximately 16,900 customers and the District of Summerland has approximately 5,500 customers which are indirectly served by FortisBC. There are also approximately 24,800 direct customers for a total of 47,200 customers in the South Okanagan region. The South Okanagan has the greatest number of indirect customers of all the regions. Table 2.3 (a) above shows both direct and indirect customer counts by region.

Operations

Operations in the South Okanagan region are managed from the Oliver operations centre. There are also field offices in Penticton and Princeton. The driving time from operations centres to some of the outlying areas in the region can be up to an hour or more. Due to rural nature of parts of the South Okanagan communities, response time for trouble calls tend to be lengthier than in the North Okanagan region.

The challenges in the South Okanagan region for the future are similar to that of North Okanagan with growing demand in some areas, particularly Osoyoos, Penticton and Oliver. In addition, the South Okanagan region also has some aging plant concerns that will require sustainment capital investments in the future.

Growth and Capital Projects

The South Okanagan region has experienced a mix of growth rates in its communities. Osoyoos and Oliver have experienced the highest load growth over the past decade. The City of Penticton, which FortisBC serves indirectly, has generally experienced lower growth.

A number of capital projects have been undertaken to meet this increased demand including:

- Two new distribution substations - Arawana in Naramata and Nk’Mip in Osoyoos. The Nk’Mip substation also included the construction of approximately 20 kilometres of new 63 kV transmission line.

- The Okanagan Transmission Reinforcement (OTR) project is the largest project undertaken by FortisBC. The OTR project provides reliable bulk transmission to both Kelowna and much of the South Okanagan and included the construction of Bentley Terminal station, approximately 28 kilometres of new 230 kV transmission line between Vaseux Lake and RG Anderson Terminal stations, a new 230 kV transformer at RG Anderson Terminal station, a rebuild of the existing Oliver Terminal, and 138 kV capacitor bank installations in both the FA Lee and DG Bell

Terminal stations in Kelowna. The majority of the OTR project is expected to be completed in advance of the 2011 summer peak, with the remaining components to be completed by the end of 2012.

Development continues to be steady in parts of the South Okanagan region for the foreseeable future, particularly Oliver, Osoyoos and Penticton. Currently there are a number of large developments underway which will result in load growth. These include:

- Development of Regal Ridge outside Osoyoos, which consists of approximately 600 residential units and a golf course;
- Development of an Osoyoos Indian Band land on the east side of Osoyoos Lake which includes the construction of approximately seven kilometres of new distribution line;
- Development of a new commercial complex in Oliver including a new Canadian Tire store;
- Development of residential units on a golf course in Oliver; and
- A number of new development proposed within the City of Penticton.

In other areas of the region such as Princeton, Keremeos and Okanagan Falls, growth is forecast to be lower for the short term but other challenges exist in these regions which require capital investment.

In 2007, FortisBC acquired the previously privately-owned Princeton Light and Power distribution system and has invested in sustainment capital projects as required. Portions of the infrastructure within the Princeton area are aging and reaching end of life. For example, as previously approved in the FortisBC 2009-2010 Capital Expenditure Plan, the Princeton distribution substation switchgear was salvaged and rebuilt. New distribution breakers and protection and control equipment were installed to increase reliability for area customers.

Growth and Sustainment capital projects for this area are listed in Table 2.3.2 below.

Table 2.3.2 - South Okanagan Projects

Timeframe	Project	Purpose	Section
2012-2013	41 Line Salvage and Distribution Underbuild Rehabilitation	To salvage the 41 Line transmission circuit along the full right of way while keeping the distribution underbuild poles in place. Distribution structures will be rehabilitated to an acceptable level accommodating a future plan to have double circuit distribution.	3.2.1
2014-2016	42 Line Meshed Operation Between Huth and Oliver	To prevent a voltage collapse during in South Okanagan 42 Line must be operated closed between Oliver and Huth.	2.8.5.1
	Kaleden Feeder 1 Capacity Upgrades	To alleviate voltage problems and regulator overloading by reconductoring a section of the feeder and relocating a regulator bank to an optimum location.	3.1.7
	Huth Substation 8 kV Breaker Replacement	Replacement of Feeder 1 and Feeder 2 circuit breakers with a suitable replacement.	2.10.4.2
	Pine Street Transformer Protection Upgrade	To upgrade the Transformer protection at the Pine Street Substation.	
	Summerland Transformer Replacement	Install more capacity at Summerland substation to avoid breach of contract demand limit.	2.8.7
	Osoyoos 63 kV Breaker Additions	Provide proper transformer protection while achieving safety concerns for operators.	2.10.4.6
	Capacitor Addition to Bentley Terminal	Addition of capacitors to the Bentley Terminal to provide voltage support to the South Okanagan.	2.8.5.2
2017-2031	RG Anderson Distribution Transformer Upgrade	Meet the Capacity requirements of the City of Penticton load.	2.8.9
	Reconductor 52 Line and 53 Line	Reconductoring of 52 Line and 53 Line to continue to provide reliable service to customers in the South Okanagan.	2.8.5.3
	Central Okanagan Station	To construct a 25 kV station to provide a long term solution to the entire area and alleviate distribution capacity problems on some of the long redials taps by converting to 25 kV. The goal would also be to salvage the OK Falls, Kaleden, West Bench, and Trout Creek substations.	2.8.22
	Vaseux Lake Terminal Transformer Addition	Install the third transformer at Vaseux Lake Terminal to provide adequate capacity.	2.8.11
	Tie distribution circuit between Kettle Valley and Nk'Mip	To construct a distribution tie line between Kettle Valley and Nk'Mip substations to improve reliability to customers in between.	3.1.9

2.3.3 KOOTENAY / BOUNDARY REGIONS

Characteristics

In general, the Kootenay / Boundary portion of the FortisBC service territory is considered a single, larger area with two smaller sub-regions. The Kootenay region includes Creston, Salmo, Fruitvale, Trail, Rossland, Castlegar, Nelson, South Slocan, Kaslo and Slocan City. The Boundary region consists of Christina Lake, Grand Forks, Greenwood, Midway and Rock Creek. The Kootenay region is the largest geographic region in the FortisBC service territory and contains 540 kilometres of transmission line and 1,846 kilometres of distribution line. The Kootenay region also includes FortisBC's four generating stations along the Kootenay River, the Lower Bonnington, Upper Bonnington, South Slocan, and Corra Linn plants. The Boundary region contains 265 kilometres of transmission line and 848 kilometres of distribution line. As seen in Table 2.3 (b) above, when combined, the Kootenay and Boundary regions account for just over 50 percent of the total transmission and distribution assets in the FortisBC service territory.

FortisBC supplies 9,200 customers indirectly through the City of Nelson and 1,900 customers through the City of Grand Forks municipal utilities. FortisBC also serves 650 customers through two BC Hydro wholesale interconnections. The total number of direct and indirect customers in this region is approximately 50,000 and represents approximately 31 percent of the total FortisBC customer count.

The Kootenay and Boundary regions are also unique in that they serve the majority of industrial accounts in the FortisBC service territory. These customers include Columbia Power Corporation (through its operating entities), Zellstoff Celgar, Interfor, Kalesnikoff Lumber, Kokanee Brewery, and Roxul.

FortisBC acquired the historic assets of the West Kootenay Power and Light Company, which originated in Rossland over 100 years ago. Thus the Kootenay / Boundary region has some of the oldest assets in the Company that are still in-service. The FortisBC sustainment capital programs have been more heavily weighted in these regions as opposed to growth capital programs in the North Okanagan and South Okanagan.

Operations

The Kootenay/Boundary region has operational centers in Grand Forks, Creston, Warfield, Castlegar and Kaslo. The Warfield Complex also includes the Kootenay Warehouse and the System Control Centre. The Trail Office accommodates the Contact Centre as well as

Engineering and Information System departments. Operations in the Kootenay and Boundary regions can be challenging due to the large geographic area and the mountainous terrain. Trouble calls can generally be reached in less than 20 minutes, but in some remote areas of the region response time can be over an hour.

When large snow or windstorms impact the Kootenay and Boundary regions, crews must spread out over the large geographic area; customers can experience lengthy outages if FortisBC crews or external resources from neighbouring regions are not available to assist.

Capital Projects

Over the past 10 to 12 years there have been projects above and beyond the normal sustainment and maintenance programs to address end-of-life infrastructure in the Kootenay region. Some of these projects included:

- the Kootenay 230 kV Supply Reinforcement project replaced eight 63 kV circuits between the FortisBC generation facilities in South Slocan and Trail with a single 63 kV line from South Slocan to Brilliant and 230 kV circuits from South Slocan to Brilliant and from Brilliant to Trail. The replacement of approximately 300 kilometres of 63 kV transmission line with 40 kilometres of 230 kV line resulted in significant improvements in reliability and reduced operations costs.
- The 30 Line voltage conversion project, which down-rated 30 Line from 161 kV operations to 63 kV. This line was originally constructed to supply the Teck (then Cominco) lead/zinc mine load in Kimberley, however the mine was decommissioned in approximately 2005. The remaining FortisBC customer load was capable of being supplied by the 63 kV transmission voltage used elsewhere in the area. This project included protection and switching upgrades and salvaged seven large power transformers that were nearing end of life. Together, this project resulted in customer benefits from improved reliability and reduced maintenance requirements going forward.
- Construction of the Kettle Valley Substation including the installation of a dual transformer 161 - 25 kV station centrally located in the Boundary region. By converting the distribution system in this area to 25 kV, the Kettle Valley Substation was able to reach further and eliminate the need for three distribution stations and approximately 100 kilometres of 63 kV transmission line.

While growth in the Kootenay and Boundary regions is not as rapid as the North Okanagan, there have been several distribution projects completed to meet growing load over the past decade. These include:

- Construction of the Ootischenia Substation, which was required to offload Castlegar and Blueberry substations;
- Construction of the Cottonwood Substation, which replaced the legacy Whitewater substation;
- Construction of the Valhalla Substation, which was built to accommodate growth in Slocan and replaced the legacy Slocan City substation; and
- Construction of Cascade Substation, which was built to supply customers in Rossland and surrounding areas and replaced the legacy Rossland substation.

Table 2.3.3 - Kootenay Boundary Projects

Timeframe	Project	Purpose	Section
2012-2013	6/26 Line Reconfiguration	To create new tap off point for 6 Line and 26 Line on the south side of the river crossing and salvage from that point north to the existing tap off point eliminating two river crossings.	2.9.5
	27 Line Rebuild	To rehabilitate 27 Line to an acceptable level to improve reliability and reduce liability from a safety point of view.	2.9.5
	Glenmerry Feeder 2 to Feeder 1 Tie Line	Construct new feeder tie to offload overloaded Glenmerry Feeder 2 and Beaver Park Feeder 1 and defer a large station upgrade at Beaver Park.	3.1.4
	19/29 Line Reconfiguration	To salvage 19 Line between South Slocan Switching Station and the Vernon-Slocan highway crossing to avoid unnecessary large capital expenditure for rebuild and potential liability.	2.9.5
	21-24 Lines River Plant	To rehabilitate the four 63 kV transmission lines to an acceptable level to avoid outages that could have large potential financial implications and to improve safety.	2.9.5
	20 Line WTS to Salmo	To rehabilitate the transmission line to an acceptable level to improve reliability and reduce liability from a safety point of view.	2.9.5
	Grand Forks Terminal Transformer Addition	Add a second terminal transformer to achieve a reliable 63 kV N-1 contingency configuration at Grand Forks Terminal.	2.8.3
	All Plants Concrete and Structural Rehabilitation Program	This program is intended to provide a sustaining level of capital investment to address deterioration of structural steel and concrete elements at all facilities. The program will target repairs to deteriorated elements on a priority basis and has been budgeted at what FortisBC deems a minimum sustaining level of investment.	2.5.1.1
	Upper Bonnington Spillgate Rehabilitation	This project was approved by BCUC Order G-195-10 as part of the 2011 Capital Plan submission and is intended to ensure the reliable operation of two spill gates at the Upper Bonnington facility.	2.5.1.2
	Lower Bonnington Powerhouse Windows	This project was approved by BCUC Order G-195-10 as part of the 2011 Capital Plan submission and is the second year of a project to replace 80+ year old windows at this facility.	2.5.1.3
	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	This project is intended to replace miscellaneous windows at these facilities based on the recommendations of an engineer's report completed in 2010.	2.5.1.4
	Corra Linn Unit 2 Life Extension	This project was approved by BCUC Order C-5-09	2.5.2.1

Table 2.3.3 - Kootenay Boundary Projects cont'd

Timeframe	Project	Purpose	Section
2012-2013	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade	This project was approved by BCUC Order G-195-10	2.5.2.3
	Corra Linn Unit 3 Completion	Corra Linn Unit 3 completion will address components not addressed during the Life Extension project for this unit in 2000, but later deemed necessary as part of subsequent Life Extension projects.	2.5.2.4
	Upper Bonnington Old Plant Various Unit Upgrades	This project is intended to ensure ongoing reliability and safety of the old units at Upper Bonnington.	2.5.2.5
	All Plants Station Service	This project was approved by BCUC Order G-147-06	2.5.2.2
	Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels	This project involves the installation of a fire panel at all four plants. This project is also being completed at South Slocan in 2011 which is approved by BCUC Order G-195-10.	2.5.3.1
	All Plants Safety and Security	This project is to increase plant safety and security by installing signage, fencing and road barriers. This project has spending from 2012-2015.	2.5.3.2
2014-2016	30 Line Lake Crossing Assessment and Rehabilitation	Assess and rehabilitate the 3.5 kilometre Kootenay Lake crossing span to an acceptable condition.	2.9.5
	Grand Forks Terminal Feeder Addition	Extending the Grand Forks distribution feeder into the Christina Lake distribution network to offload the Christina Lake transformer.	3.1.8
	All Plants Concrete and Structural Rehabilitation Program	This program is intended to provide a sustaining level of capital investment to address deterioration of structural steel and concrete elements at all facilities. The program will target repairs to deteriorated elements on a priority basis and has been budgeted at what FortisBC deems a minimum sustaining level of investment.	2.5.1.1
	Corra Linn Spillgate and Spillway Concrete Rehabilitation	The Corra Linn spill gates and spillway are used to control the levels of the Kootenay Lake. They were originally installed in 1932, and were not installed with a method of isolation, making routine maintenance difficult. This project is intended to rehabilitate the gates and spillway as required to ensure continued reliable operation, as well as address the lack of isolation for these gates.	2.5.1.5

1 **Table 2.3.3 - Kootenay Boundary Projects cont'd**

Timeframe	Project	Purpose	Section
2017-2031	Upper Bonnington, Lower Bonnington and Corra Linn Plant Automation	Plant automation is intended to assist in the transition from time based to condition based maintenance. The business case to support this project will be based on data retrieved from the South Slocan Plant automation project approved in 2011 under BCUC Order G-195-10	2.5.2.6
	All Plants Fire Safety	This project involves upgrading the fire egress and fire stops in the powerhouses at all four river plants.	2.5.3.3
	All Plants Safety and Security	This project is to increase plant safety and security by installing signage, fencing and road barriers. This project has spending from 2012-2015.	2.5.3.2
	Creston Area Capacity Increase	To upgrade capacity in the Creston Substation and feeders to meet the growing load demands.	2.8.23
	Boundary Area Supply Upgrade	Upgrade one of the terminal transformers at AS Mawdsley terminal to a larger unit to continue to provide reliable service.	2.8.12
	Beaver Valley Solution	Upgrade the Beaver Valley to 25 kV to eliminate the need for the Fruitvale and Hearns substations.	2.8.8
	Reconductor 31 Line	Reconductor 31 Line to a higher rated conductor to meet growing demand in Creston.	2.8.13
	All Plants Concrete and Structural Rehabilitation Program	This program is intended to provide a sustaining level of capital investment to address deterioration of structural steel and concrete elements at all facilities. The program will target repairs to deteriorated elements on a priority basis and has been budgeted at what FortisBC deems a minimum sustaining level of investment.	2.5.1.1
	Upper Bonnington Overflow Spillway Concrete Resurfacing	The Upper Bonnington overflow spillway was originally constructed in 1916 and has not been refurbished since construction. The spillway is an integral part of the dam, and the project will restore the spillway to design condition.	2.5.1.7
	South Slocan Spillway Concrete Repair	The South Slocan dam is 80+ years old and the concrete in the spillway has begun to show signs of deterioration. The project would be focused on resurfacing and rehabilitating the spillway as required to extend the life of the asset.	2.5.1
	All Plants Headgate and Spillgate Superstructure upgrade	The headgates and spill gates at all facilities are operated by hoists located above deck level on a structural steel lattice work superstructure. These structures have not been rehabilitated since installation, and recent engineering assessments have identified the potential need for seismic upgrades as well as routine rehabilitation work to ensure their long term viability.	2.5.1.8

2

Table 2.3.3 - Kootenay Boundary Projects cont'd

Timeframe	Project	Purpose	Section
2017-2031	Lower Bonnington Spill Gate Rebuild	The spill gates at Lower Bonnington are over 80 years old. There is currently a risk of the gates jamming and not opening during maximum flood conditions, resulting in water over topping the dam and causing damage to the powerhouse. Deterioration as a result of age as well as corrosion can cause the collapse of skin plates (outer steel plates), which would cause water to spill from the dam.	
	Upper Bonnington, Corra Linn and South Slocan Window Replacement	A proposed capital project in 2013 will address the worst locations in these powerhouses, but given the age of the remaining windows it is expected that the balance of the windows will require replacement within the next 30 years.	2.5.1.2
	All Plants Heating and Ventilation	This project will install automatic louvers and controls to remotely operate and maintain environmental parameters at the facility	2.5.2.7
	Upper Bonnington Old Plant Repowering	The four old units located at the Upper Bonnington facility will be upgraded and rehabilitated as part of this large capital project.	2.5.2.8
	All Plants Fire Water Supply	At all four plants the fire water supply must be upgraded to comply with Fire Safety recommendations.	2.5.2.9
	Mechanical Equipment Replacement	This project is to upgrade mechanical equipment that is expected to be a risk of failure due to age and condition of equipment.	2.5.2.10
	Electronic Equipment Replacement	This project is to replace obsolete electronic equipment.	2.5.2.11
	Corra Linn Unit 3 Turbine Replacement	This turbine is original from 1932 and will be replaced based on condition and age.	2.5.2.13
	Upper Bonnington Unit 6 Turbine Replacement	This turbine is original from 1940 and will be replaced based on condition and age.	2.5.2.14
	Corra Linn Unit 3 Generator Rewind	This project is to replace the generator windings based on condition.	2.5.2.12
	Dam Safety Instrumentation	This project is to install concrete and dam structure monitoring equipment as a result of anticipated Dam Safety Requirements.	2.5.3.4

2.4 Generation

2.4.1 OVERVIEW OF FORTISBC GENERATION

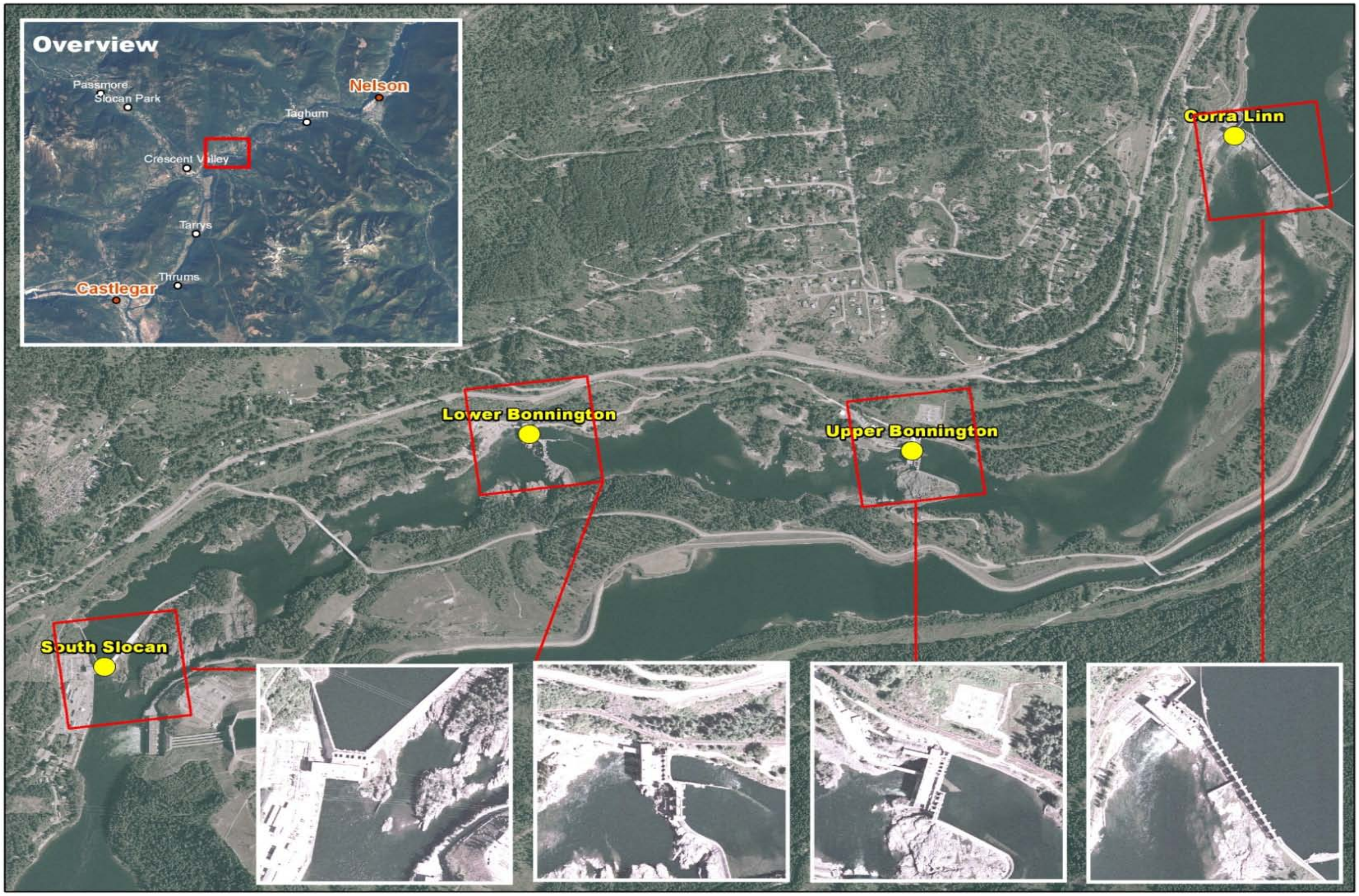
FortisBC and its predecessor companies have been providing power in the region for over a century. Prudent investment in the generation infrastructure has been a key to past success and will continue to play an important role in the future.

FortisBC currently owns and operates 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. Refer to Figure 2.4.1 for the dam locations.

The four generating facilities provide a source of low cost embedded energy to FortisBC customers through the Canal Plant Agreement (CPA). The Canal Plant Agreement was originally signed in August 1972 and was amended by the Entitlement Adjustment Agreement in June 2004. The Canal Plant Agreement permitted the construction of the BC Hydro Kootenay Canal Plant by compensating FortisBC (then West Kootenay Power) for the use of a portion of FortisBC's water rights on the Kootenay River.

The Canal Plant Agreement provides FortisBC with an annual energy and capacity entitlement which is intended to represent the amount of generation FortisBC would have received from the four river plants had the Kootenay Canal Plant not been constructed. The CPA permits BC Hydro to divert water to its Kootenay Canal Plant, and to manage the watershed to the overall benefit of the system. Under the CPA, FortisBC must ensure that all the generating units in the four river plants are continuously available for service. If a unit is forced out of service, FortisBC is obligated to replace the lost energy at market prices. The energy from the CPA is included in FortisBC's 2012 Resource Plan (2012 Integrated System Plan, Volume 2) for the service of its customers, and represents the lowest cost energy in the Company's resource stack.

Figure 2.4.1 - Location of FortisBC Generation



2.4.2 CAPITAL EXPENDITURES - 1998 TO 2011

The terms of the Canal Plant Agreement, primarily the requirement to be available for service at all times, drives many of the business decisions related to maintenance and capital investment in the generation facilities. In 1998, the Company began extensive mechanical and electrical upgrades under a program known as the Upgrade and Life Extension (ULE) program. The ULE Program is commonly referred to as a “water to wire” upgrade meaning that the work addresses all the necessary mechanical and electrical components directly responsible for the generation of hydro electricity. The ULE Program focused on integrating new technologies including upgrades to head gates, trash racks, turbines, generators, switch gear, station service and unit transformers. Recent advances in turbine and generator winding technology provided the opportunity to increase the capacity of many of the generators. By embarking on this program, the Company was able to retain its entitlement under the CPA, and ensure that this low cost energy was protected for its customers for the foreseeable future. Over the past twelve years FortisBC has successfully completed ten of eleven ULE. The final unit is scheduled for completion by the end of 2011.

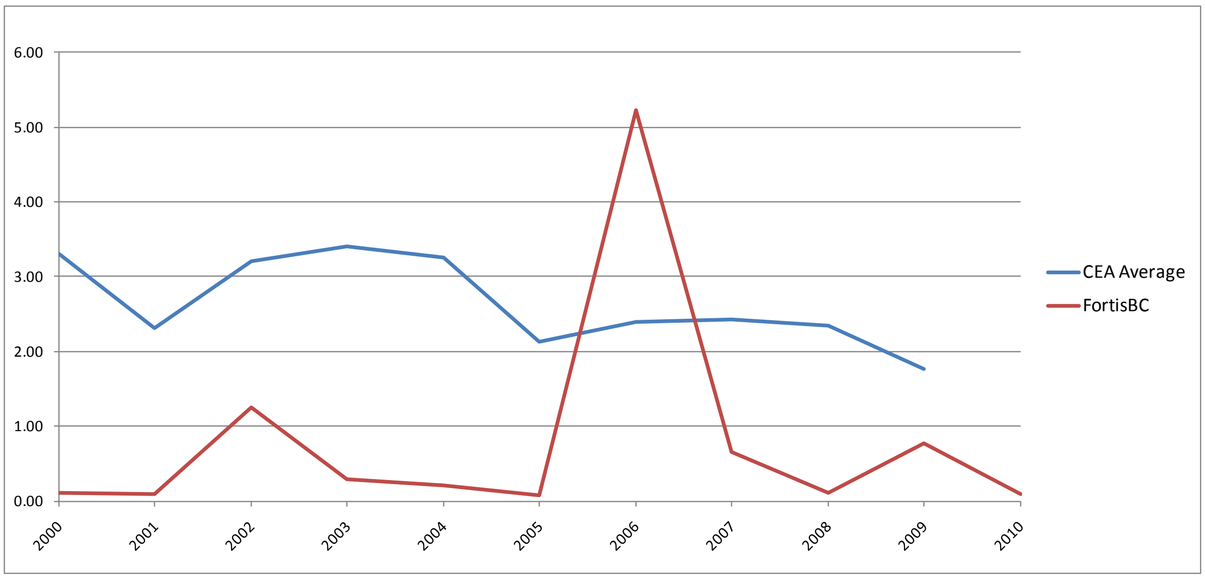
At the end of 2011 the combined generating capacity of the four plants recognized under the CPA is estimated to be 226.6 MW, supplied by 15 units ranging in size from five MW to 23 MW. At the completion of the program, FortisBC customers will receive approximately 1,612 GWh of low cost embedded energy representing approximately 45 percent of the Company’s total energy needs. The cost to generate this energy is estimated at 2 - 3 cents per kWh and represents the lowest cost energy in the FortisBC resource stack. Overall, the ULE Program is anticipated to result in over 25 MW of capacity increases and approximately 90 GWh/year of energy entitlement increases. In 2012, this will result in approximately $3.0 million in avoided power purchase costs.

In addition to this major investment in the generation units, the Company also has completed many other capital upgrades to its generation facilities since 2005. These projects have been focused primarily on replacement and overhauls of aging equipment, such as upgrades to powerhouse cranes, rehabilitation of headgates (done concurrently with ULE projects), upgrades to oil collection systems and detection, lighting upgrades and sewage and domestic water system upgrades.

2.4.3 RELIABILITY

As noted, a primary driver in determining the type of capital expenditures at generation is based on the ability to be available for service at all times, and therefore compliant with the terms of the CPA. The Company is measured on its reliability through the use of the Forced Outage Rate (FOR%) which is calculated by dividing the total number of hours in a year that a unit is removed from service due to a forced outage event by the total number of available hours for that unit in a year. The graph below illustrates FortisBC's reliability since 1994 as compared to the CEA average for similar sized units. The spike in FOR% in 2006 was the result of an insulation failure on Lower Bonnington Unit 2 transformer, resulting in 158 days of forced outage time.

Figure 2.4.3 - FortisBC Generation Reliability - Forced Outage Rate (FOR%)



As can be seen from the graph, FortisBC has maintained excellent reliability at its facilities. Although the reliability exceeds the CEA average, it also results in cost savings for the customer as any forced outage event requires the Company to pay replacement energy costs under the terms of the CPA. The amount of these costs varies with the cost of power at the time of the outage. For example, if Unit 1 at South Slocan (installed capacity 23 MW) were to be forced out of service, the replacement energy costs could range from $77,000 to $90,000 per week. If the Company was also required to replace capacity as a result of the outage event, that could result in an additional monthly capacity charge of approximately $94,000. The replacement energy and capacity charges noted above assume the current BC Hydro rates under the existing Power Purchase Agreement.

2.4.4 UPPER BONNINGTON UNITS 1 TO UNIT 4 (THE OLD PLANT)

Although the ULE program is coming to an end, there are still four units within the FortisBC power system that have not been included within this program. Unit 1 to Unit 4 at Upper Bonnington have not been rehabilitated since their installation, and have been under consideration for a repowering project for several years. While evaluating the need to repower the old units, the Company did invest $5.5 million from 2005 to 2010 to address issues which were required to ensure the ongoing safe and reliable operation of the facility. Issues addressed over this time frame included:

- Replacement of two switchyard 63 kV oil breakers and adding oil spill containment throughout the plant;
- Upgrading the intake area, including concrete refurbishment to the forebay piers and deck;
- The purchase of new stop logs and seals, replace intake gate gantry and upgrade intake gates;
- Upgrades to the tailrace area include concrete refurbishment to the tailrace piers and deck, replace tailrace gantry, replace seals on the tailrace stoplogs, and corrosion control on the tailrace gates; and
- In the power house a new power crane, upgrades to dewatering system, asbestos containment and removal, and spare exciter rebuild.

The units themselves are located in the old section of the Upper Bonnington facility and have a total generating capacity of approximately 20 MW. The need to upgrade these units has been assessed on the basis of risk of failure, overall benefit to our customers, and the potential rate impact as a result of undertaking the upgrade. The assessment demonstrated the need to maintain this generation resource for the benefit of FortisBC customers, but also indicated that since the units are still operating satisfactorily, the project is not required at this time. Recognizing the age of the equipment, the Company expects that normal operation of this equipment could require higher maintenance costs over time. As well, it must be recognized that the reliability of this plant cannot match that of the plants which have had Unit Life Extensions. In order to ensure that the Old Plant units continue to operate safely, the Company will address some operation concerns in 2012 (section 2.5.2.8), the condition and operation of these units will be continually monitored. The timing of any proposed rebuild project will be dependent on the condition of the component parts and the Company's ability to continue to operate these units in a safe, reliable, and cost effective manner. Any such rebuild project would the subject of a separate regulatory filing.

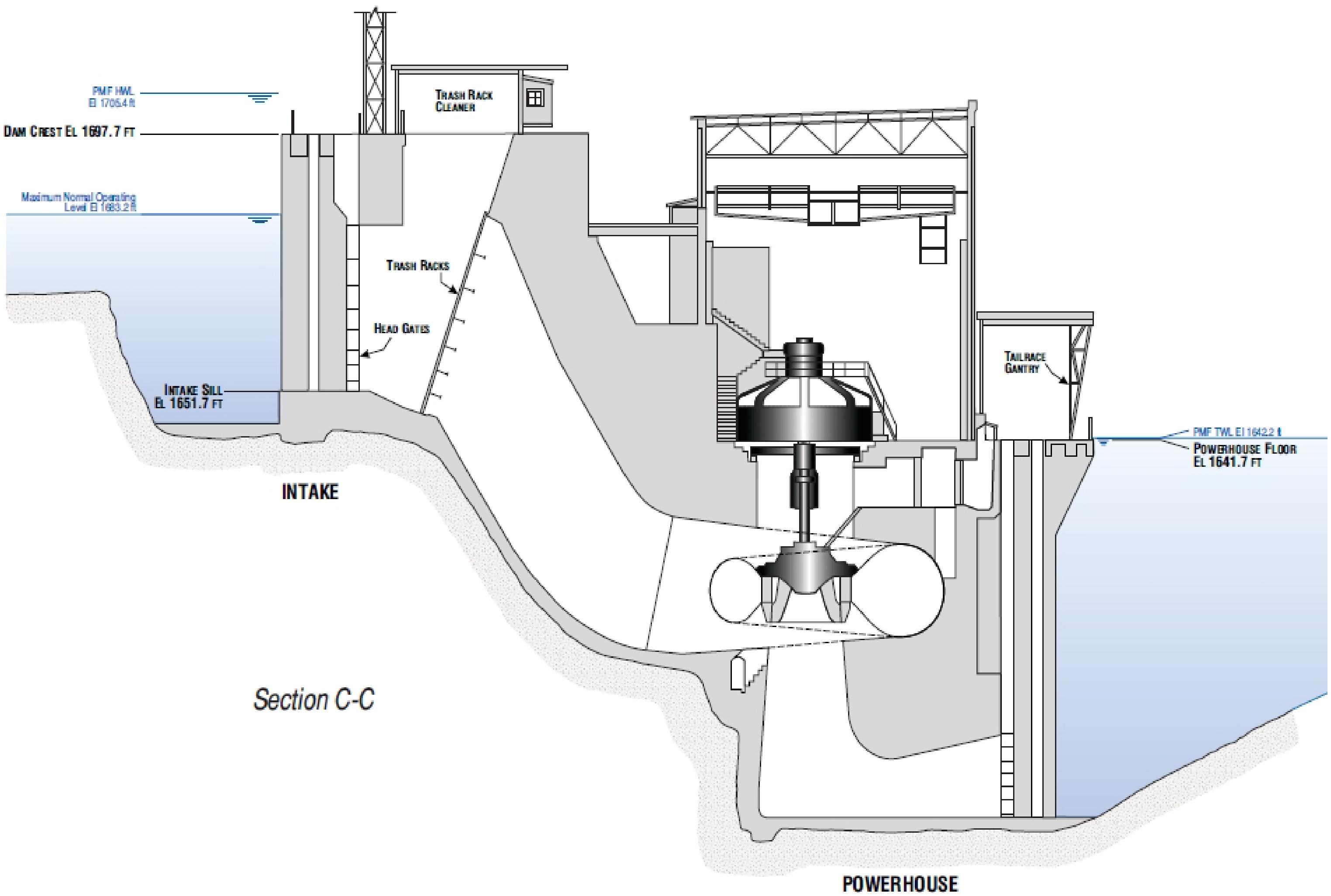
2.4.5 PHYSICAL CIVIL INFRASTRUCTURE

The primary focus of the capital investments in Generation since 1998 has been on the major mechanical and electrical equipment necessary to generate electricity. As noted above, the Company will have completed rebuilding 11 of its 15 generating units by the end of 2011. Figure 2.4.5 (a) below shows the typical components that are rehabilitated, rebuilt or replaced, including the generator, turbine, head gates, trash racks and miscellaneous auxiliary equipment directly associated with a unit such as governor systems, excitation systems and electronic controls.

With the completion of these major mechanical and electrical components essential to power generation, the Company intends to turn its focus towards the physical infrastructure which supports these components. Beyond the water to wire components addressed in the ULE program, there are many civil and structural components which require sustaining capital investments to ensure their long term viability. Figure 2.4.5 (b) below shows a plan view of the Upper Bonnington Power plant, which can be taken to be typical of the physical infrastructure components found at all four facilities. The major components of the facility itself include the powerhouse, dam, spillway, spill gates, access roads, headgate and spill gate superstructures and overflow weirs.

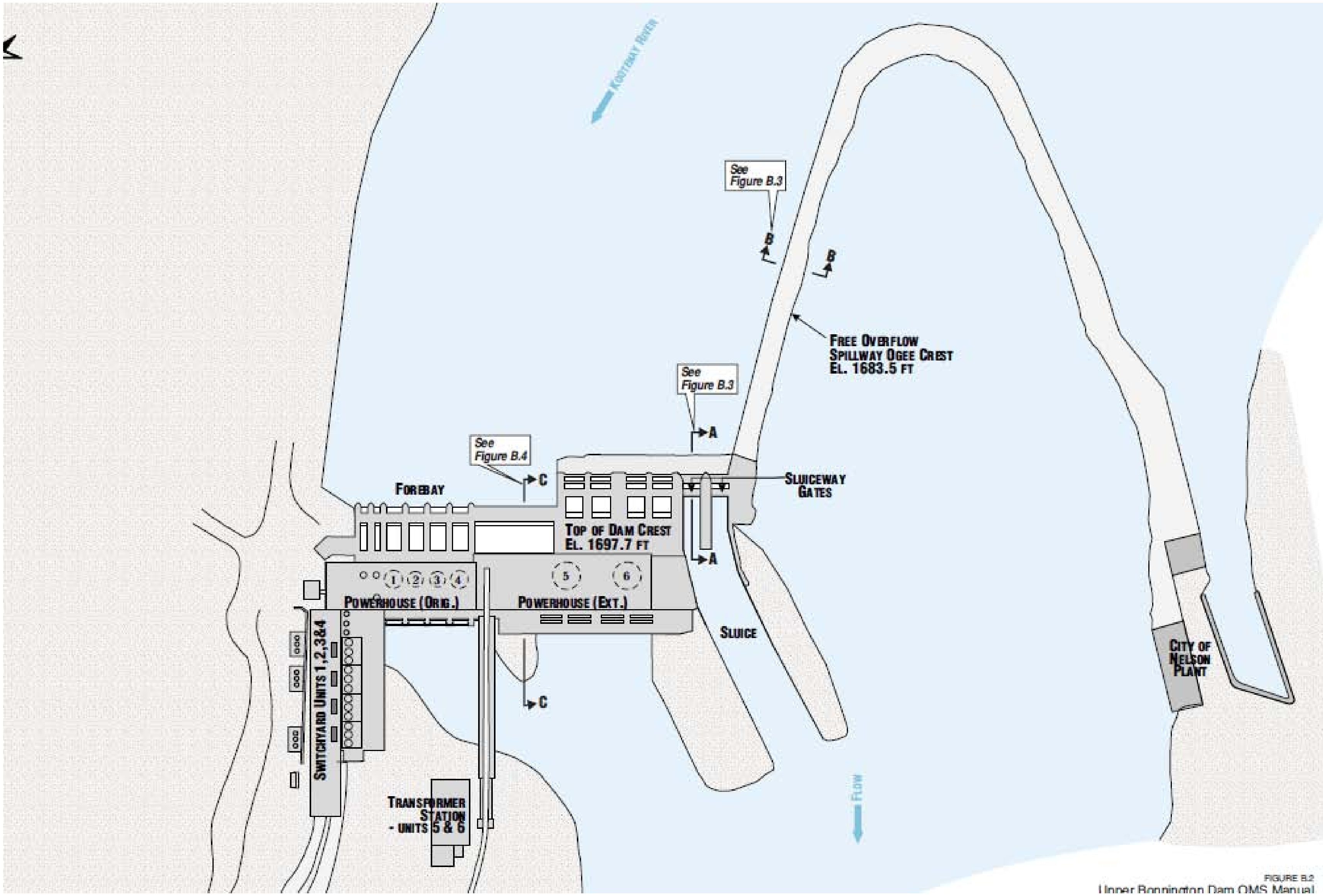
Dating back to 1963, the Company has undertaken miscellaneous civil work to upgrade the facilities, most notably the seismic upgrade program from 1992 to 1994. In addition to this seismic work, resurfacing projects on select elements (South Slocan wing dam and Lower Bonnington spillway) were completed in 1963 and 1981. Additional concrete rehabilitation work at Corra Linn, South Slocan and Upper Bonnington was performed from 1995 to 2000. Typically, this investment in physical infrastructure has been sporadic, primarily because the age of the facilities did not dictate a need for major repairs and capital investment was focused on aspects of the operations with greater priority.

1 **Figure 2.4.5 (a) - Typical power plant cross-section**



2

Figure 2.4.5 (b) - Plan View of Upper Bonnington



In many instances, the concrete and structural steel in these various components have not been addressed or worked on since the original construction of the facilities over 80 years ago. In other cases, changing design standards and regulations require components to be upgraded or replaced. As the facilities age, there is a requirement for capital investment to ensure continued safe and reliable operation.

2.5 Generation Capital Projects

Generation projects are broadly classified as Physical Infrastructure, Mechanical and Electrical Systems, Dam, Public and Worker Safety or All Plants Minor Sustainment Capital. Table 2.5 below outlines the specific projects intended to be undertaken by Generation over the forecast period. The projects themselves are then further described.

1 **Table 2.5 (a) - Generation Sustainment Projects**

1	Generation Projects	2012	2013	2014	2015	2016	2017-31
2	**Physical Infrastructure**			($000s)			
3	All Plants Concrete and Structural Rehabilitation	570	617	647	665	686	14,454
4	Upper Bonnington Spill Gate Rebuild (G-195-10)	1,085	-	-	-	-	-
5	Lower Bonnington Powerhouse Windows	366	8		-	-	-
6	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	430	-	-	-	-
7	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	-	-	7,874	865	1,786	17,326
8	Upper Bonnington Overflow Spillway Concrete Resurface	-	-	-	-	-	30,576
9	South Slocan Spillway Concrete Repair	-	-	-	-	-	42,370
10	All Plants Superstructure Upgrade	-	-	-	-	-	5,020
11	Lower Bonnington Spill Gate Rebuild	-	-	-	-	-	1,779
12	Remaining Powerhouse Window Replacement	-	-	-	-	-	2,949
13	**Total Physical Infrastructure Projects**	**2,021**	**1,055**	**8,521**	**1,530**	**2,472**	**114,474**
14							
15	**Mechanical and Electrical Equipment**						
16	Corra Linn Unit 2 Life Extension(C-5-09)	3,423	-	-	-	-	-
17	All Plants Station Service (G-147-06)	672	-	-	-	-	-
18	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade (G-195-10)	90	-	-	-	-	-
19	Corra Linn Unit 3 Completion	722	-	-	-	-	-
20	Upper Bonnington Old Plant Various Unit Upgrades	1,311	-	-	-	-	-
21	Upper Bonnington, Lower Bonnington and Corra Linn Plants Automation	-	-	283	291	301	-
22	All Plants Heating and Ventilation	-	-	-	-	-	8,711
23	Upper Bonnington Old Unit Repowering	-	-	-	-	-	57,080
24	All Plants Fire Water Supply	-	-	-	-	-	2,431
25	Mechanical Equipment Replacement	-	-	-	-	-	4,340
26	Electronic Equipment Replacement	-	-	-	-	-	4,340
27	Corra Linn Unit 3 Generator Rewind	-	-	-	-	-	4,344
28	Corra Linn Unit 3 Turbine Replacement	-	-	-	-	-	3,974
29	Upper Bonnington Unit 6 Turbine Replacement	-	-	-	-	-	3,974
30	**Total Mechanical and Electrical Equipment**	**6,218**	**-**	**283**	**291**	**301**	**86,763**

Table 2.5 (a) - Generation Sustainment Projects cont'd

	Generation Projects	2012	2013	2014	2015	2016	2017-31
31	**Dam, Public and Worker Safety**	**($000s)**					
32	Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels	250					
33	All Plants Safety and Security	471	259	264	-	-	-
34	All Plants Fire Safety	-	475	424	437	-	-
35	All Plants Surveillance and Security	-	-	1,001	1,031	1,065	738
36	Dam Safety Instrumentation	-	-	-	-	-	5,991
37	**Total Dam, Public Worker Safety Projects**	**721**	-	-	-	-	2,391
38			**734**	**1,689**	**1,468**	**1,065**	**9,120**
39	**All Plants Minor Sustainment**						
40	All Plants Minor Sustainment Capital	1,171					
41	**Total All Plants Minor Sustainment Projects**	**1,171**	1,158	1,203	1,144	1,182	20,902
42			**1,158**	**1,203**	**1,144**	**1,182**	**20,902**
43	**Total Generation Projects**	**10,131**					

2.5.1 PHYSICAL INFRASTRUCTURE

There is a requirement to invest sustainment capital dollars into the physical infrastructure at the Generation facilities. This work will include concrete rehabilitation, structural steel rehabilitation, seismic upgrades, spill gate rehabilitation, rock scaling, and other projects intended to extend the life of the asset. Aside from the Upper Bonnington Old Plant Repowering, this sustainment category represents the largest component of the proposed expenditures in the 20 year forecast period. Table 2.5.1 below shows a complete list of projects and programs for the 2012 - 2031 timeframe to ensure that the aging infrastructure at the four facilities is rehabilitated cost-effectively.

Table 2.5.1 - Physical Infrastructure Projects and Programs

	Physical Infrastructure	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	All Plants Concrete and Structural Rehabilitation	570	617	647	665	686	14,454
2	Upper Bonnington Spill Gate Rebuild (G-195-10)	1,085	-	-	-	-	-
3	Lower Bonnington Powerhouse Windows	366	8		-	-	-
4	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	430	-	-	-	-
5	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	-	-	7,874	865	1,786	17,326
6	Upper Bonnington Overflow Spillway Concrete Resurface	-	-	-	-	-	30,576
7	South Slocan Spillway Concrete Repair	-	-	-	-	-	42,370
8	All Plants Superstructure Upgrade	-	-	-	-	-	5,020
9	Lower Bonnington Spill Gate Rebuild	-	-	-	-	-	1,779
10	Remaining Powerhouse Window Replacement	-	-	-	-	-	2,949
11	**Total Physical Infrastructure Projects**	**2,021**	**1,055**	**8,521**	**1,530**	**2,472**	**114,474**

2.5.1.1 All Plants Concrete and Structural Rehabilitation Program

Although FortisBC has undertaken projects to complete seismic upgrades of the dams, continuous sustainment capital investments are required to maintain safe facilities, extend the life of the physical assets and ensure ongoing compliance with dam safety guidelines. With major mechanical and electrical components upgraded, the next phase will be the implementation of an effective concrete and structural rehabilitation program. The primary drivers for such a program are discussed in greater detail below.

Concrete Deterioration

The four facilities located on the Kootenay River system were constructed between 1897 and 1940. These facilities are considered to be gravity dams and were constructed using reinforced concrete. Over the past 70 and more years these structures have been subjected to various forces causing deterioration. There are many environmental factors that can lead to concrete deterioration but for clarity only some of the major factors are discussed below.

Some of the major factors involved in the deterioration of concrete structures along the Kootenay River system are as follows:

Carbonation

Carbonation is a reaction between carbon dioxide in the atmosphere, water and concrete. The reaction is known to reduce the pH surrounding the rebar. This allows the reinforcing steel to begin to corrode.

Photo 2.5.1.1 (a)

Corra Linn Air Chamber Roof showing deterioration caused in part by carbonation. Spalling concrete can be seen on the underside of the beam and reinforcing steel is visible in both the slab and the beam.

De-icing salts

De-icing salts are known to break down the protective film surrounding the reinforcing through the ingress of chloride ions. Once the protective film is removed the reinforcing begins to corrode.

Photo 2.5.1.1 (b)

Lower Bonnington Tail Race Deck showing deterioration caused in part by de-icing salts.

Freeze thaw

Freeze thaw deteriorates concrete as the water within the concrete freezes and expands. When the water expands within the concrete cracking occurs. With each cycle, larger cracks and openings appear within the concrete allowing deeper penetration of the following cycle.

Photo 2.5.1.1 (c)

Lower Bonnington Tail Race Gantry support beam showing deterioration caused in part by freeze thaw action.

Hydraulic erosion

Hydraulic erosion is caused by a combination of cavitation and the abrasive action of water and the debris it carries.

Photo 2.5.1.1 (d)

Lower Bonnington Intake Piers showing deterioration caused in part by hydraulic erosion.

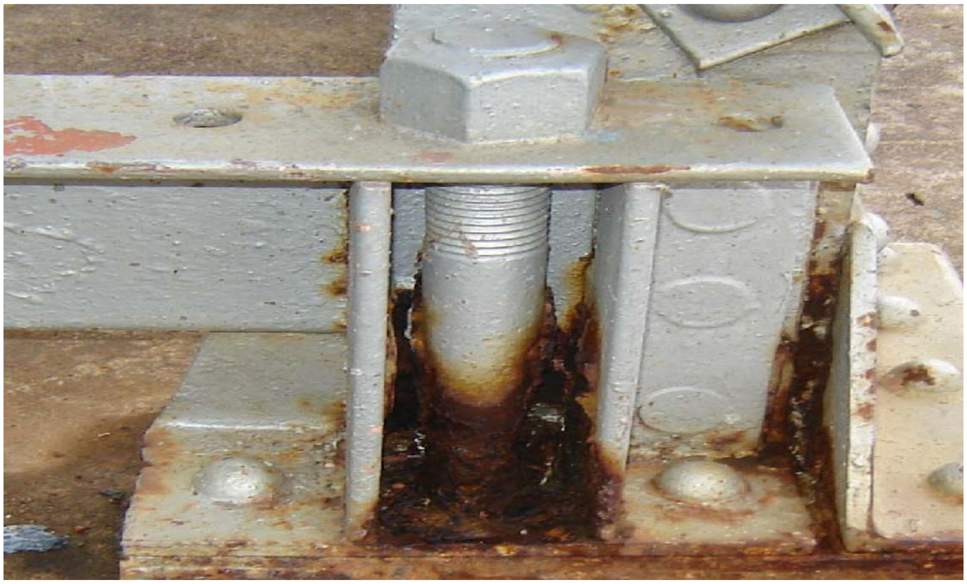
Structural Deterioration

The primary process behind the deterioration of structural steel at the facilities is corrosion - commonly known as rust. Measures have been taken during the lifespan of the facilities to minimize the amount of steel corrosion. However, most of the steel structures have been in use for more than 70 years and now require rehabilitation.

Over the past number of years, various engineering investigations have been conducted to properly quantify the need for structural restoration. In addition to structural deterioration, these reports cover changes to dam safety regulations, seismic design standards and updates to structural design standards.

Aside from expected deterioration due to age, the structural components (i.e. headgate superstructures) were found to have relatively few structural concerns at this time. Further work is required in future years to determine what impact changing seismic design requirements both in the BC Building Code and updated Dam Safety Guidelines may have on future rehabilitation and upgrade work on the structural steel elements in the plants. Additionally, the Corra Linn spill gates have specific concerns and will be addressed as a separate regulatory filing. In an effort to maintain these structures into the future, FortisBC has included projects for painting of structural steel and repairs as recommended by these engineering assessments.

Photo 2.5.1.1 (e)



Lower Bonnington Intake Superstructure showing deterioration of anchor bolts.

Consequences of Delay

Increases Deterioration

Within the four major items identified as sources of concrete deterioration, there are two items that typically accelerate once the process has begun. These are freeze thaw and hydraulic erosion.

Freeze thaw deterioration of concrete is known to reach what is commonly referred to as “distress” under critical moisture saturation. This “distress” occurs when the moisture content of the concrete is optimal for the freeze-thaw deterioration. With each cycle, larger cracks and openings appear within the concrete allowing deeper penetration of freezing and thawing and consequently even greater deterioration.

Cavitation is a major component of hydraulic erosion. Cavitation is known to form at surface irregularities along the flow path. The process of hydraulic erosion creates more of these irregularities over time, with more surface irregularities there are more locations for cavitation to occur, increasing the erosion rate.

Although the actual rate of increased deterioration is difficult to predict, it is reasonable to anticipate that the current deterioration present at the facilities will begin to increase more rapidly over time. This increase in deterioration will in turn increase the scope of concrete repair necessary to maintain the generation facilities.

Possibilities of Failures

There are two processes that affect the integrity of the reinforcing steel within reinforced concrete. The combination of carbonation and the application of de-icing salts at the generation facilities have led to some deterioration in areas with the potential for failure.

As mentioned earlier, the processes of carbonation and the application of de-icing salts lead to deterioration of the reinforcing steel. This reinforcing steel carries the tension component of the load which cannot be carried by the concrete alone. Deterioration of the reinforcing steel ultimately leads to a reduction in the structural capacity.

Over the years engineering knowledge has evolved and so have the standards for determining design loads. Design loads are typically the worst case criteria that a structure is likely to experience within its lifespan. As a consequence, most structures do not frequently see their design loads. This allows for structures to continue to “appear to perform” as intended, even as they deteriorate.

The combination of the reduction of structural strength, design load requirements which have been increased since the construction of the facilities and the infrequent application of full loading can lead to dangerous situations and unexpected failures.

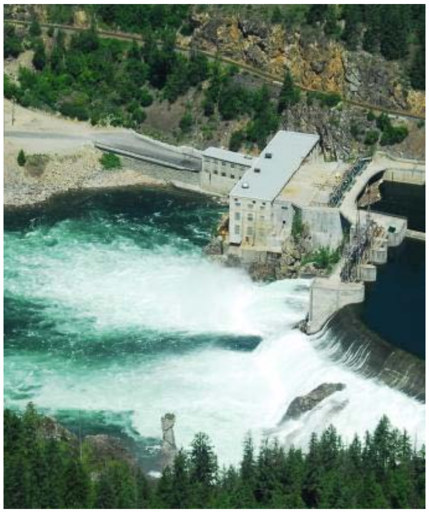
Increased Construction Costs

Without addressing the potential impact of major failures, there are two factors to consider when evaluating the potential cost impacts of delaying rehabilitation. The first being the increased deterioration that will occur over the additional years and the second being the notable increase in construction costs.

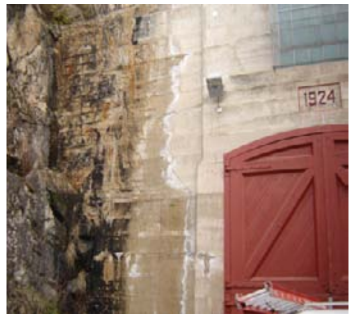
Although difficult to accurately estimate, FortisBC anticipates a considerable increase in the amount of deterioration at the generation facilities should the concrete and structural rehabilitation be delayed. In an effort to quantify the order of magnitude, excluding major projects, the oldest facility - Lower Bonnington - currently accounts for 47 percent of the estimated rehabilitation. The remaining 53 percent (17.7 percent average) is shared by the other facilities that are an average of 24 years newer. This leads to an estimated growth in scope of concrete and structural deterioration of 4.2 percent compounded annually. The combination of increased deterioration combined with increasing construction costs seen across the province since 2007 indicates that delay in the civil rehabilitation program could result in much higher costs in future years. FortisBC has completed a review of all the required civil rehabilitation work and has proposed a program which will levelize the expenditures based on priority to address areas on a condition basis.

Some typical deterioration examples from each generating facility are shown below.

Photo 2.5.1.1 (f) - Lower Bonnington Dam



Freeze Thaw

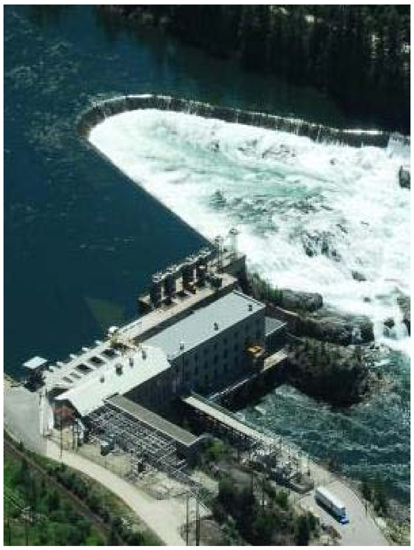


Hydraulic Erosion

Hydraulic Erosion

Freeze Thaw

Photo 2.5.1.1 (g) - Upper Bonnington Dam

	**Concrete Deterioration** 	**Concrete Deterioration** 
	Structural Deterioration 	**Carbonation** 

The concrete and structural work is divided into a rehabilitation program and major projects. The concrete and structural rehabilitation program is spread over a 20 year period and is levelized to provide regular sustaining investment in the facilities and prevent large capital expenditures in future years. There are also three major projects envisioned, which will be the subject of future regulatory filings.

The concrete and structural rehabilitation program addresses items such as small upgrades to structural steel to meet new earthquake and loadings standards along with repair of deteriorated concrete structures. For those structures with minor deterioration, FortisBC will resurface the concrete and recoat the steel structures to extend their useful life.

Table 2.5.1.1 - All Plants Concrete and Structural Rehabilitation Costs

Year	2012	2013	2014	2015	2016	2017-31
	($000s)					
Cost	570	617	647	665	685	14,454

2.5.1.2 Upper Bonnington Spill Gate Rebuild

This project was approved by Commission Order G-195-10. The scope of work for 2011 involves modifications to the existing structure to provide a means of isolating the existing spill gates for rehabilitation and ongoing future maintenance. Work scheduled for 2012 includes the refurbishment of the existing gates

Expenditures for this project are estimated to be $1.09 million in 2012.

2.5.1.3 Lower Bonnington Powerhouse Windows

This project was approved by Commission Order G-195-10 and involves replacing the power house windows in 2011 and 2012.

The project costs are estimated to be $0.366 million in 2012 and $0.008 million in 2013.

2.5.1.4 Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows

Windows in the powerhouses at all four of FortisBC's generating plants are manually operated on a routine basis to regulate the temperature within the powerhouse. Depending on the facility, the windows range in age from 70 to 100 years and due to deterioration of component parts, are at risk of falling out, creating a risk to the safety of plant personnel during operation of the windows.

FortisBC has engaged an engineering consultant to provide an independent assessment of the windows in the Upper Bonnington, South Slocan and Corra Linn facilities. Windows identified to be at risk of failure at these facilities based on the engineer's assessment have been scheduled for replacement or refurbishment within this project.

FortisBC expects this phase of the project to cost $0.43 and to be substantially completed in 2013. Any windows not required to be replaced in 2013 will be addressed a future time.

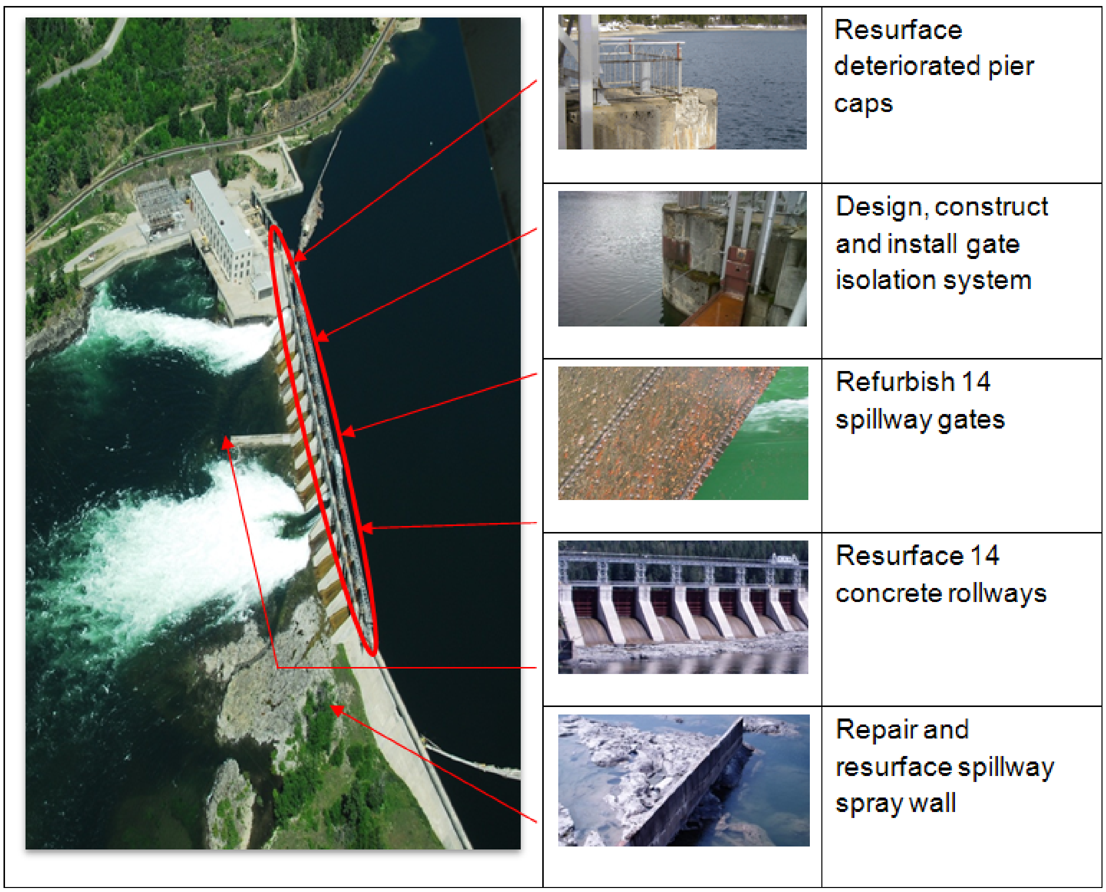
2.5.1.5 Corra Linn Spillgate and Spillway Concrete Rehabilitation

This major project involves refurbishment of all fourteen spill gates at the Corra Linn dam. These gates are an integral part of controlling water levels on Kootenay Lake and the flows on Kootenay River including inflows into BC Hydro's Kootenay Canal Plant. The gates were originally installed during dam construction in 1932, and have not been refurbished since. The scope of this project includes construction of an access road, installation of a gate isolation system, gate refurbishment and concrete refurbishment. Areas of work are shown in Photo 2.5.1.5 below. This multi-year project has expenditures estimated at $27.85 million and is planned to begin in 2014 and be completed by 2030 as shown in Table 2.5.1.5

Table 2.5.1.5 -Corra Linn Spillway Concrete and Spill Gate Rehabilitation Costs

Year	2014	2015	2016	2017-31
	($000s)			
Cost	7,874	865	1,786	17,326

Photo 2.5.1.5 - Scope of Corra Linn Spillway Concrete and Spill Gate Rehabilitation



2.5.1.6 South Slocan Spillway Concrete Repair

The overflow spillway concrete portion of the South Slocan dam needs concrete rehabilitation in order to ensure safe and reliable dam operations. The South Slocan dam is over 80 years old and the concrete has started to deteriorate. Photo 2.5.1.6 below shows the overflow spillway area. This is a multi-year project with estimated expenditures of $42.37 million. It is planned to begin in 2023 and be completed by 2026.

Photo 2.5.1.6 - Scope of South Slocan Spillway Repair

Repair and Resurface Overflow Spillways

2.5.1.7 Upper Bonnington Overflow Spillway Concrete Resurface

The Upper Bonnington dam, originally built in 1916, has an overflow spillway which has not been refurbished since construction. This spillway is an integral part of the dam, which must be maintained to ensure generating capacity. Included in the scope of this project is the development of a safe means of access to allow for rebar and concrete replacement while ensuring that a portion of the spillway remains available to spill water when required. Photo 2.5.1.7 shows the overflow spillway area. This is a multi-year project with estimated expenditures of $30.58 million. It is planned to begin in 2026 and be completed by 2030.

Photo 2.5.1.7 - Scope of Upper Bonnington Overflow Spillway Concrete Resurface

Repair and Resurface Overflow Spillways

2.5.1.8 All Plants Superstructure Upgrade

The headgates and spill gates at all facilities are operated by hoists located above deck level on a structural steel lattice work superstructure. These structures have not been rehabilitated since installation, and recent engineering assessments have identified the potential need for seismic upgrades as well as routine rehabilitation work to ensure their long term viability. A failure in the structures would prevent the head gates from closing or the spill gates from opening in an emergency situation. This upgrade includes re-grouting of steel support columns as required, replacing support steel as required and controlling corrosion on all headgate and spill gate superstructures. There are a total of six structures as all four FortisBC river plants require upgrading. This upgrade is estimated to cost $5.02 million in the 2022 - 2030 timeframe.

2.5.2 MECHANICAL AND ELECTRICAL EQUIPMENT

This category is intended to capture all work required on the mechanical systems due to age and condition of equipment. Examples are upgrades for plant ventilation and air wash systems which are used to cool the generating units, dewatering pumps including piping which ensures safe maintenance access to areas which would normally be submerged, air systems including piping which are use for the generator brakes and general plant service air, turbine replacements (when not completed as part of the ULE), and one anticipated generator rewind. In 15 to 20 years some electronic and computer controlled equipment is anticipated to be obsolete. Exciters, governors, protective relays, and programmable logic controllers (PLCs) are examples of such equipment which will have computer components no longer supported by the manufactures and for which replacement parts will no longer be available. In addition, the Upper Bonnington Repowering project is included in this category as it will represent the next and last large investment in major equipment in FortisBC regulated fleet of generators. At this time, this project represents the bulk of the planned expenditures, and as mentioned previously the timing of this project will be triggered by the condition of the existing equipment and the ability of the Company to operate safely and cost effectively within the parameters of the Canal Plant Agreement.

Also included in Mechanical and Electrical equipment is a series of turbine replacements at Corra Linn and Upper Bonnington. These turbines are scheduled for replacement as normal end of life operations. These replacements are not scheduled for another 15 years and are based on the life expectancy of this type of component. Actual condition and operating characteristics will be assessed prior to making final decisions on this type of replacement.

Table 2.5.2 - Mechanical and Electrical Equipment

	Mechanical and Electrical Equipment Projects	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Corra Linn Unit 2 Life Extension(C-5-09)	3,423	-	-	-	-	-
2	All Plants Station Service (G-147-06)	672	-	-	-	-	-
3	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade (G-195-10)	90	-	-	-	-	-
4	Corra Linn Unit 3 Completion	722	-	-	-	-	-
5	Upper Bonnington Old Plant Various Unit Upgrades	1,311	-	-	-	-	-
6	Upper Bonnington, Lower Bonnington and Corra Linn Plants Automation	-	-	283	291	301	-
7	All Plants Heating and Ventilation	-	-	-	-	-	8,711
8	Upper Bonnington Old Unit Repowering	-	-	-	-	-	57,080
9	All Plants Fire Water Supply	-	-	-	-	-	2,431
10	Mechanical Equipment Replacement	-	-	-	-	-	4,340
11	Electronic Equipment Replacement	-	-	-	-	-	4,340
12	Corra Linn Unit 3 Generator Rewind	-	-	-	-	-	4,344
13	Corra Linn Unit 3 Turbine Replacement	-	-	-	-	-	3,974
14	Upper Bonnington Unit 6 Turbine Replacement	-	-	-	-	-	3,974
15	**Total Mechanical and Electrical Equipment**	**6,217**	**-**	**283**	**291**	**301**	**89,194**

2.5.2.1 Corra Linn Unit 2 Life Extension

The Corra Linn Unit 2 Life Extension was approved by Commission Order C-5-09. The generating unit will be returned into service in December 2011, with completion of final project tasks including final efficiency testing of the turbine in the second quarter of 2012. The project will be fully closed out in the fourth quarter of 2012 after final inspection of the turbine.

The costs are estimated to be $3.42 million in 2012.

2.5.2.2 All Plants Station Service

This project was approved by Commission Order G-147-06 and involves the installation of new equipment and back-up power sources to ensure operational reliability and to address environmental concerns at all four FortisBC generating plants. South Slocan was completed in 2009 and Corra Linn was completed in 2010. Lower Bonnington is scheduled for completion in 2011 and Upper Bonnington will be completed in 2012. The costs are estimated to be $0.67 million in 2012.

2.5.2.3 Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade

This project was approved by Commission Order G-195-10 and involves replacing seven existing PSI Quad 4 meters with five new PML-7650 meters. This is a two-year project that will start in 2011 and be completed in 2012.

The costs are estimated to be $0.09 million in 2012.

2.5.2.4 Corra Linn Unit 3 Completion

The Corra Linn Unit 3 Life Extension was completed in 2000 and was the second project to be undertaken in the FortisBC Upgrade/Life Extension (ULE) program which began in 1998. Since the time of the project, the scope of the ULE program has evolved and the scope of the more recent projects encompasses a greater scope of work which has been determined required to properly extend the life of all components of the generator unit. The Corra Linn Unit 3 Completion project will include items which were not completed as part of the scope of the original life extension in 2000, but were later determined as necessary upgrades on all remaining life extension projects. All the other generating units on the ULE program have received the necessary upgrades to meet the Company's reliability and environmental standard. Proposed work includes installing new trash racks, upgrading the transformer bay oil spill containment, upgrading mechanical switches and valves and the procurement of spare generator coils.

This project is estimated to cost $0.72 million with an in-service date of 2012.

2.5.2.5 Upper Bonnington Old Plant Various Unit Upgrades

As noted previously, the Company has determined that the Upper Bonnington Old Plant, with many components approaching 100 years in age, will require a rebuild at some point in the future. Currently, the need to rebuild these units has been assessed on the basis of risk of failure, overall benefit to our customers, and the potential rate impact as a result of undertaking the upgrade. The assessment demonstrated the need to maintain this generation resource for the benefit of FortisBC customers, but also indicated that since the units are still operating satisfactorily, a full rebuild project for the Upper Bonnington Old Plant is not required at this time. Recognizing the age of the equipment, the Company expects that normal operation of this equipment could require higher maintenance costs over time. Since many of the major components of the Upper Bonnington generating units 1-4 are approaching 100 years in age, it is proposed to invest in sustaining capital projects designed to ensure ongoing safety and reliability for the Upper Bonnington Old Plant.

The scope of work for this project includes sustaining capital work on head gate seals, generators, turbines, governors and unit transformers. For example, the head gate seals require new sealing timbers. The generator, turbine and governor require replacement and rehabilitation of some mechanical components such as links, pins, bushings and brake system refurbishment to ensure reliable service of these components. The unit transformers require development of a connection point for a mobile sub to mitigate outage times in the event of a transformer failure.

This project is estimated to cost $1.31 million with an in-service date of 2013.

2.5.2.6 Upper Bonnington, Lower Bonnington and Corra Linn Plant Automation

Currently, FortisBC utilizes primarily a time based maintenance system in its generation facilities, and intends to move towards a condition based maintenance system which will permit improved maintenance decisions on the new equipment installed in the facilities. Under a condition based maintenance program, the timing of maintenance intervals can be more closely matched with equipment need. It is expected that the intervals between certain maintenance activities, most notably major overhauls currently undertaken on a ten year interval, may be extended based on the condition of the equipment. The move towards an asset management model is intended to minimize equipment life cycle cost and maximize equipment reliability for the benefit of customers.

The investment in automation equipment at these three plants will be based on a business case created from information collected in the installation of plant automation at South Slocan.

This project is estimated to cost $0.28 million in 2014, $0.29 million in 2015 and $0.30 million in 2016.

2.5.2.7 All Plants Heating and Ventilation

Installation of heating and ventilation systems in all plants is required to better cool the powerhouses and the units during the summer months when temperatures increase to levels which require the unit loading to be reduced to keep the generator windings and electronic equipment from exceeding recommended operating temperatures. Extended periods of operating at high temperatures will cause a decrease in equipment life.

At all four plants automated louvers are to be installed to control the flow of outside air throughout the plant. At Lower Bonnington an air wash plant which uses river water for cooling, will be installed.

This project is estimated to cost $8.71 million with an in-service date of 2030.

2.5.2.8 Upper Bonnington Old Unit Repowering

The majority of the equipment for Units 1 to 4 are currently over ninety years old and have exceeded their anticipated operating life. This project is to complete a water to wire refurbishment of these units similar to the ULE program at the remaining FortisBC plants. This project is discussed in greater detail in Section 2.4.4.

This project is estimated to cost $57.08 million with an in-service date of 2020.

2.5.2.9 All Plants Fire Water Supply

The existing fire water supply is fed from surrounding area creek water systems. This project is to address an increase in water supply volume as recommended in engineering reports.

This project is estimated to cost $2.43 million with an in-service date of 2025.

2.5.2.10 Mechanical Equipment Replacement

A number of mechanical systems require upgrades due to age and condition. Many of the pumps, motors and fans are original equipment installed 80 or more years ago. They have been maintained throughout the years, but are at an age where they will need to be replaced.

This project is estimated to cost $4.34 million with an in-service date of 2034.

2.5.2.11 Electronic Equipment Replacement

Many of the generator systems such as governors, exciters, protective relays and control systems now use electronics and computers. This electronic equipment installed in the past ten years, will only have a life span of 25 years and this project will address upgrades to this equipment.

This project is estimated to cost $4.34 million with an in-service date of 2034.

2.5.2.12 Corra Linn Unit 3 Generator Rewind

Corra Linn Unit 3 received a Generator Rewind during the ULE in 2000. Several coils installed during the ULE did not pass quality control standards but remained in the unit due to the high cost to repair. Monitoring of the coils has indicated that their current condition is acceptable, however it is expected that this generator will require a rewind in the future.

This project is estimated to cost $4.34 million with an in-service date of 2026.

2.5.2.13 Corra Linn Unit 3 Turbine Replacement

This turbine was originally installed in 1932. An assessment prior the Corra Linn Unit 3 ULE in 2000 indicated that a replacement was not required at that time. It is anticipated that based on the age, the condition of the turbine will deteriorate over time with a replacement turbine required at some point..

This project is estimated to cost $3.97 million with an in-service date of 2026.

2.5.2.14 Upper Bonnington Unit 6 Turbine Replacement

This turbine was originally installed in Unit 5 in 1940. An assessment prior to Upper Bonnington Upgrades in 2003 recommended that the turbine be refurbished and re-installed. This turbine was refurbished and re-installed in Unit 6. It is anticipated that its condition will deteriorate and a replacement will be required.

This project is estimated to cost $3.97 million with an in-service date of 2026.

2.5.3 DAM, PUBLIC AND WORKER SAFETY

Projects in this category are proposed to ensure the ongoing compliance with health and safety regulations, the obligation of the Company to protect public safety in and around its facilities and the need to ensure the dams and spillway structures meet the minimum requirements of the *Provincial Water License Act* and the *Canadian Dam Safety Guidelines*.

Dam Safety

The Company is obligated by both its duty to maintain its facilities in accordance with good utility practice and by the provisions of its Water Licenses to ensure a robust Dam Safety program. Dam Safety Guidelines continue to expand as new developments occur within the various disciplines of engineering. Engineering principles are continually evolving, resulting in increased attention to several areas of dam safety. For example today's standard seismic concerns and testing such as finite element analysis of dams, were rarely taken into account 20 years ago. FortisBC is anticipating that advances in technology will continue to refine the standard used to judge dam safety in British Columbia. These new standards may in turn come with future costs that cannot be anticipated at this time.

FortisBC is anticipating changes in the *Dam Safety Regulations* that would require the installation of monitoring equipment at its facilities to ensure that structures are performing as anticipated. Some typical types of monitoring equipment are slope inclinometers to measure ground movement, piezometers to measure internal pressures within the dam and crack gauges to measure movement of the dam. The Company will continue to observe developments in this area of Dam Safety and will propose projects required to maintain a standard of good utility practice.

Security

The question of security at FortisBC facilities has received increased attention over the past decade, and this focus on security is expected to increase over the next 20 years. Regular communication with Canadian Security Intelligence Service (CSIS) and the international nature of the Columbia River Treaty requires FortisBC to be cognizant of security issues and ensure that these issues are managed around facilities. FortisBC has initiated a review of security and found that the current security at its Kootenay River facilities has the potential for improvement.

Public and Worker Safety

In conjunction with the other programs, FortisBC will be pursuing programs to improve public safety, plant safety and security. In the near future FortisBC will continue with plant fire system and evacuation upgrades at all facilities. Public safety surrounding facilities will be addressed by a four-year program.

There have been substantial changes in fire code regulations over the past century; as a result, generation facilities do not meet current BC Building Code requirements. Although dams are not governed by the BC Building Code, FortisBC has a responsibility to its employees and considers the fire upgrades as an important part of its safety program. FortisBC proposes to continue fire system upgrades and install fire rated doors and partitions within facilities to ensure that personnel can safely exit during a fire.

Public safety was recently introduced as part of the Canadian Dam Safety Guidelines. There are inherent risks surrounding the daily operation of dams including strong currents, rapidly changing water levels and automatic equipment startup such as spillway gates. To increase public awareness and safety around its facilities FortisBC is implementing a four-year program in 2012 to protect the public from hazards and restrict public access to hazardous locations. This program will include the installation of barriers, gates and fencing.

Table 2.5.3 - Dam, Public and Worker Safety

	Dam, Public and Worker Safety Projects	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels	250	259	264	-	-	-
2	All Plants Safety and Security	471	475	424	437	-	-
3	All Plants Fire Safety	-	-	1,001	1,031	1,065	738
4	All Plants Surveillance and Security	-	-	-	-	-	5,991
5	Dam Safety Instrumentation	-	-	-	-	-	2,391
6	**Total Dam, Public Worker Safety Projects**	**721**	**734**	**1,689**	**1,468**	**1,065**	**9,120**

2.5.3.1 Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels

This project involves the installation of a fire alarm panel at Upper Bonnington, Lower Bonnington and Corra Linn Plants. Presently there is no alarm system in the plant except for the water deluge system for the generating units. The proposed fire alarm panel will be multi zone and will include fire full stations; audible and visual alarms; and fire and smoke detectors. This alarm panel is for employee safe egress only. The panel will not include controls nor will it be linked to a suppression system. The fire panel will annunciate to a central monitoring location.

This project is estimated to cost $0.77 million with an in-service date of 2014.

2.5.3.2 All Plants Safety and Security

This project is to upgrade safety and security at the four FortisBC generating plants by increasing the level of hazard awareness brought about by the posting of signs and the increased perimeter fencing which will restrict access to dangerous or controlled areas. This work is considered good utility practice for Dam Safety, Public Safety and Security requirements.

This project is estimated to cost $1.81 million with an in-service date of 2015.

2.5.3.3 All Plants Fire Safety

This project involves upgrading the fire egress from the power houses at all four river plants. The upgrades will include new exits from the river side of the turbine floor to the outside via the operating floor, enclosing stairways with fire rated walls, upgrading wooden doors with metal fire doors, adding crash bars to the doors, installing fire stop to all openings between rooms and floors and upgrading the generator fire deluge system

This project is estimated to cost $3.84 million with an in-service date of 2017.

2.5.3.4 All Plants Surveillance and Security

All Plants Surveillance and Security is intended to increase the level of security around the facilities to include surveillance cameras, video recording equipment, crash proof access gates and upgrade security access identification. The Company will continue to observe developments in this area of Dam Security and will further define the scope of this project to maintain a standard of good utility practice.

2.5.3.5 Dam Safety Instrumentation

This project is to address the need for a higher level of monitoring of the concrete dam structures anticipated to be required by *Dam Safety Regulations*. Instrumentation and monitoring equipment such as slope inclinometers and piezometers will be installed at all four plants.

This project is estimated to cost $2.39 million with an in-service date of 2020.

2.5.4 ALL PLANTS MINOR SUSTAINING CAPITAL

This program involves expenditures for completing multiple minor repair jobs that have been identified at the generating plants as a result of safety inspections, storm damage, aging equipment, reports by on-call personnel and other inspections. The type of work required can range from replacement of fans and motors to upgrade of crane components to replacement of embedded piping. In all cases, the individual projects are estimated to be less than $500,000 in value. By grouping all small sustaining projects into one ongoing project, FortisBC is able to spread the cost over multiple years and manage the expenditures based on the priority and needs at that time. It also provides a mechanism to complete small capital projects which arise throughout the year as a result of component failures, safety issues or damage due to freshet or storms which otherwise would not be budgeted for. A list of proposed projects is created for each year, and the projects selected are based on a priority rating system.

Table 2.5.4 - All Plants Minor Sustainment Capital

Year	2012	2013	2014	2015	2016	2017-31
	($000s)					
Cost	1,171	1,158	1,203	1,144	1,182	20,902

2.6 Networks Systems

2.6.1 PREVIOUS SYSTEM DEVELOPMENT PLANS

FortisBC developed and filed a 1998 Transmission and Distribution System Master Plan (1998 Master Plan), a major focus of which was a review of system limitations which could be predicted to occur over a 20-year planning horizon, and to identify and analyze all prospective system development options which would offer relief for system issues.

Numerous system improvements were identified, the two largest projects being the Kootenay 230 kV System Development (completed in 2004) and the South Okanagan Supply Reinforcement (completed in 2007. Regional transmission and distribution reinforcement and upgrade projects in the Kelowna, Oliver/Osoyoos, Boundary and east and west Kootenay areas were also proposed.

A focus of the 1998 Master Plan was the number of transmission-related outages and the resulting impact on customer reliability. These transmission outages occurred due to the fact that much of the transmission system at that time was operated radially. In other words, most transmission stations had only one normal source of supply. If that supply was lost due to a forced outage, customers in the area would experience an outage until the system could be manually reconfigured to use an alternate supply (if one was available). To resolve this issue, the Master Plan identified the need for both system reinforcements and improvements in protection and communication systems.

In 2004, FortisBC filed its 2005-2024 Transmission and Distribution System Development Plan (2005 SDP). This plan, which built on the 1998 Master Plan, identified the need for further investments in the Okanagan, Boundary and Kootenay area transmission and distribution systems, and in the communications, protection and SCADA (Supervisory Control and Data Acquisition) systems owned by the Company.

The 2005 SDP identified the urgent requirement to add capacity at multiple locations in both the distribution and transmission system throughout all the regions. A number of system development options were described which would adequately mitigate the identified system deficiencies, although in some cases the ultimate configurations had not been determined at the time the 2005 SDP was issued.

In all, more than 100 system development and improvement projects were to be implemented over the subsequent six-year period, including a number of projects required to serve increasing loads largely driven by population growth in the FortisBC service area.

Detailed updates to the 2005 SDP were filed in 2005, 2006 and 2008 and included updated load forecasts and equipment condition assessments. The Company has substantially executed the SDP by way of its 2006, 2007-2008 and 2009-2010 Capital Expenditure Plans. With a few exceptions as identified in the SDP updates, the major 2005 SDP projects planned during the medium term will have been completed by year-end 2011.

In the six years since the 2005 SDP was issued, the Vaseux Lake Terminal station and bulk transmission system Remedial Action Schemes (RAS) have been completed, the Big White transmission line and substation have been completed along with many other distribution substation and capacity upgrades in both the Okanagan and Kootenay regions. The Okanagan Transmission Reinforcement (OTR) project, the largest project ever completed by FortisBC, is needed to continue to supply reliable transmission service to the entire Okanagan region and is scheduled for completion by the summer of 2012. The implementation of these projects marks substantial completion of the bulk system upgrades identified in the 2005 SDP, and provides a solid foundation for the future.

The Table 2.6.1 below outlines capital expenditures during the period between 2005 and 2010.

Table 2.6.1 - Networks System Development Expenditures 2005 - 2010

Expenditure Categories	2005 Actual	2006 Actual	2007 Actual	2008 Actual	2009 Actual	2010 Actual
	($000s)					
Transmission and Stations	58,271	45,091	69,068	46,961	49,985	80,647
Distribution (net of CIAC)	25,305	28,909	25,411	24,755	23,658	23,923
Telecommunications, SCADA, and Protection and Control	708	1,161	1,184	2,872	2,549	2,168

Note: excluding cost of removal.

2.6.2 MAJOR PROJECTS UNDERTAKEN SINCE 2005 SYSTEM DEVELOPMENT PLAN

The most significant projects completed since 2005 include:

- Comprehensive rehabilitation initiatives on 44 Line to Osoyoos and 49 Line to Summerland;
- Completion of distribution system rebuilds and voltage upgrades in Rossland, Warfield and West Trail;

- Capacitor additions at FA Lee Terminal in Kelowna and Vernon Terminal (BC Hydro) to improve import capacity into Okanagan region;
- Circuit switcher additions at Kaleden, OK Falls and Waterford to improve 63 kV sub-transmission performance in the South Okanagan;
- Rehabilitation project at AA Lambert Terminal in Creston to provide distribution backup to the Creston area was completed in 2004 and included preparation for planned 230 kV bus reconfiguration in 2006 and 2007;
- Completion of the Kootenay 230 kV System Development Project with an in-service date of 2004. Project included new 230 kV transmission circuit connecting BC Hydro’s Kootenay Canal Generating Station with Columbia Power Corporation’s (CPC) new Brilliant Terminal Station and the new Warfield Terminal Station. This project also involved salvage of most of the deteriorated 63 kV transmission lines in the West Kootenay region between South Slocan and Trail, along with salvage of the deteriorated Warfield and Tadanac substations;
- Completion of the South Okanagan Supply Reinforcement Project with an in-service date of 2005. This project included a new 500/230/161 kV substation connecting the BC Hydro 500 kV circuit between Selkirk and Nicola to the FortisBC transmission system. The 230 kV bus was temporarily operated at 161 kV until the first 230 kV circuit was completed between the Vaseux Lake and RG Anderson Terminal stations, at which time the bus was energized at its planned 230 kV operating. The ultimate configuration involves a six position 230 kV ring bus terminating three 500/230 kV transformers, two 230 kV circuits between Vaseux Lake and RG Anderson and a single 230 kV circuit between Vaseux Lake and the new Bentley Terminal near Oliver;
- Completion of the Kelowna Area Upgrade including the DG Bell Terminal 230 kV Upgrade with an in-service date of 2005. Project included termination of 230 kV circuit 73 Line at DG Bell and the addition of a new 230/138 kV transformer and FA Lee Terminal station as well as the reconfigure of 138 kV bus and transformer protection to improve capacity and reliability of supply to the City of Kelowna; and

- Distribution Substation Automation Program, scheduled for completion by the end of 2011. This project involves upgrading of protection, control, metering and communications systems at 32 legacy substations.

2.7 Transmission and Stations

2.7.1 TRANSMISSION PLANNING

The purpose of the FortisBC transmission network is to transport electric energy from generation resources and BC Hydro interconnection points to FortisBC customers. A robust transmission network must be planned and designed to provide as many of the following conditions as possible:

- Reliable delivery of power to continuously changing customer demands under a wide variety of system operating conditions, taking into account planned as well as forced outages;
- Identification and development of system upgrades required to meet customer load growth in an economically efficient manner, while maintaining high reliability standards;
- Ability to meet obligations and requirements of the FortisBC Electric Tariff;
- Development of new generation as required to serve load growth;
- Economic exchange of electric power with other systems and industry participants;
- Unconstrained access to energy supply markets during normal and extreme market conditions; and
- Flexibility and ability to support future developments, such as smart grid technologies.

The FortisBC transmission network is a critical component of the integrated system and has a large impact on customer service reliability. Its function will continue to be critical in the future to connect FortisBC customers to market resources and new generation infrastructure.

2.7.2 THE FORTISBC ELECTRICITY TRANSMISSION NETWORK

Like many utilities, FortisBC faces challenges related to the long-distance transmission of energy from the point of generation to the point of consumption. The geography of the

FortisBC service territory is such that the majority of the system load is in the Okanagan region while the FortisBC generation plants are in the Kootenay region.

The FortisBC transmission network consists of approximately 1,400 kilometres of high voltage transmission lines, which transport electricity from generating stations and contract supply points to distribution substations. The energy is then transformed to lower voltages and distributed by 5,600 kilometres of distribution lines to customer homes and businesses. Table 2.7.2 shows the lengths of overhead transmission lines by voltage class for each FortisBC region.

Table 2.7.2 - Transmission Line Lengths by Region and Voltage Class

Region	**63 kV**	**138 kV**	**161 kV**	**230 kV**	**Total**
			(kms)		
North Okanagan	2	114	0	114	230
South Okanagan	164	104	56	31	355
Kootenay	396	3	87	52	538
Boundary	164	0	103	0	266
Total	**726**	**221**	**246**	**197**	**1,390**

Until recently, much of the FortisBC transmission system was operated radially. For example, most of the FortisBC load in the South Okanagan was supplied directly from a single transmission line originating in the Trail area. However, with the completion of the Vaseux Lake Terminal Station in 2006, it is now possible for the FortisBC bulk transmission system to be operated fully meshed from Kelowna through to the Kootenay River generating stations. This system meshing has benefits, both by improving system reliability as well as by reducing transmission system losses.

FortisBC has recently added, or is in the process of adding, internal bulk transmission capacity through the following projects:

- Kootenay 230 kV Project - completed in 2004
- South Okanagan (Vaseux Lake) Project - completed in 2007
- Okanagan Transmission Reinforcement (OTR) Project - scheduled for completion in 2012

Combined, these three major projects create two strong 230 kV bulk-transmission networks: one in the Okanagan and one in the Kootenay region as shown in the simplified diagrams

1 shown below. Refer to Appendix A for a listing of the substations three-letter naming
2 designations.

3 **Figure 2.7.2 (a) - Okanagan Bulk Transmission Network**

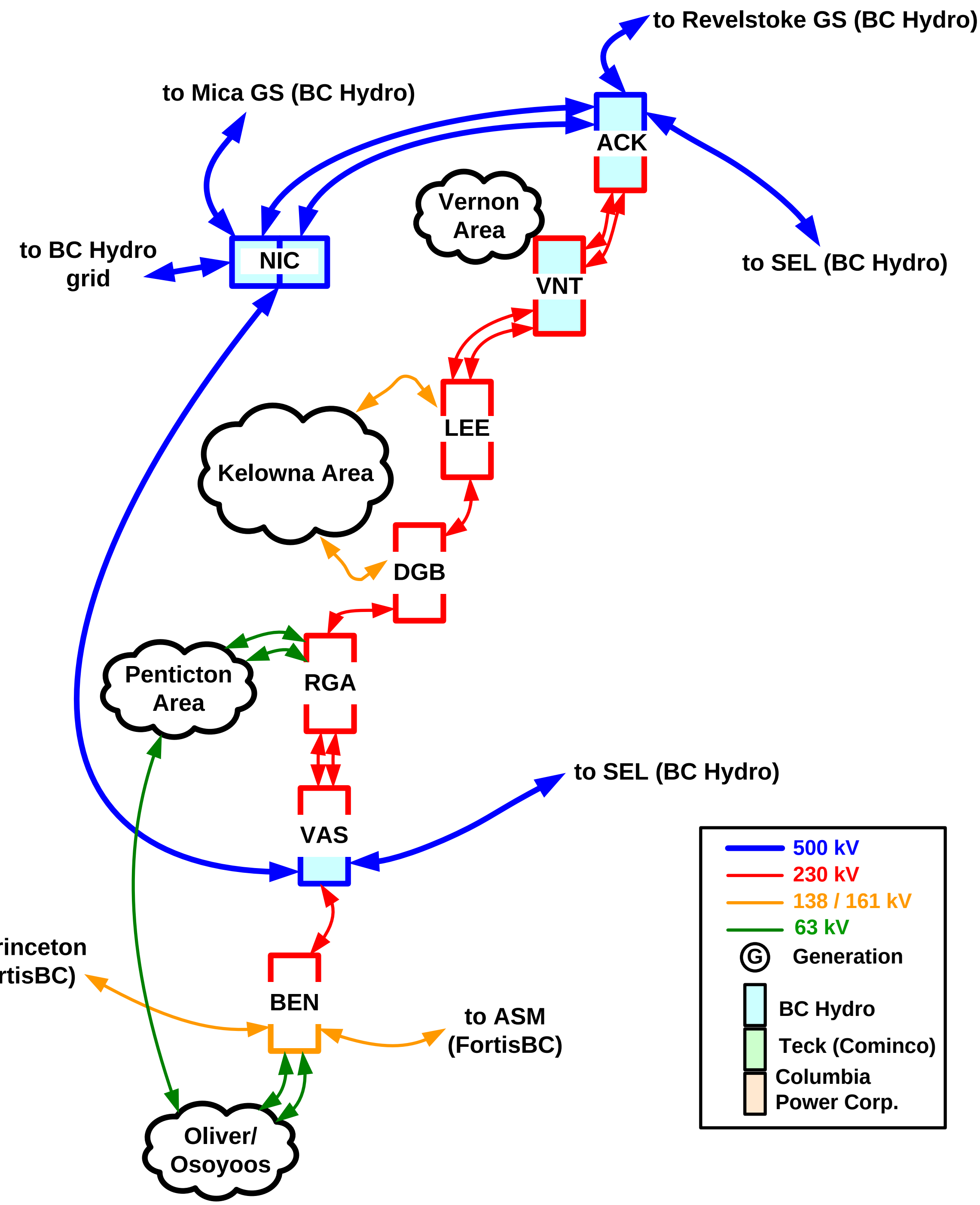


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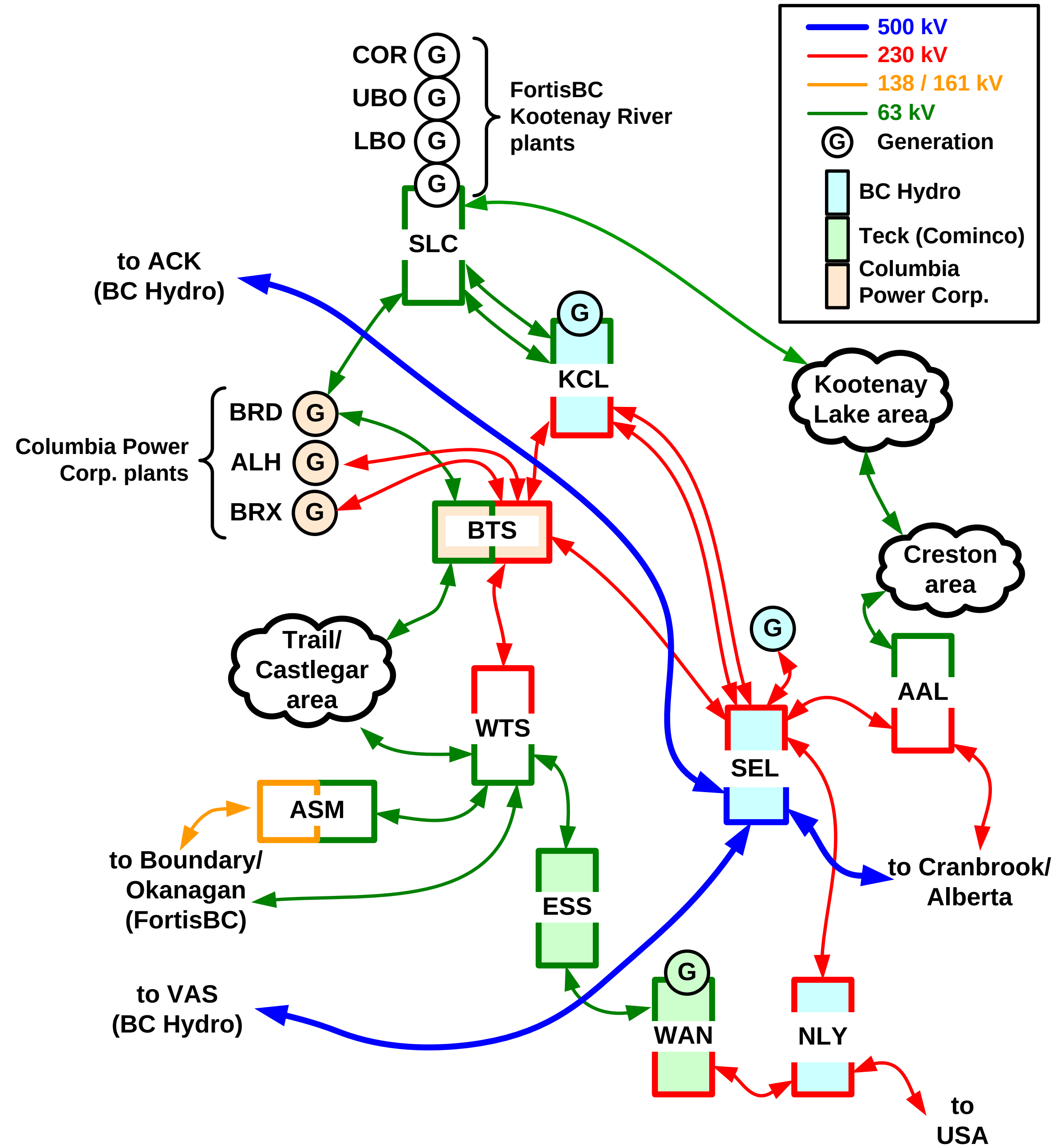
Figure 2.7.2 (b) - Kootenay Bulk Transmission Network



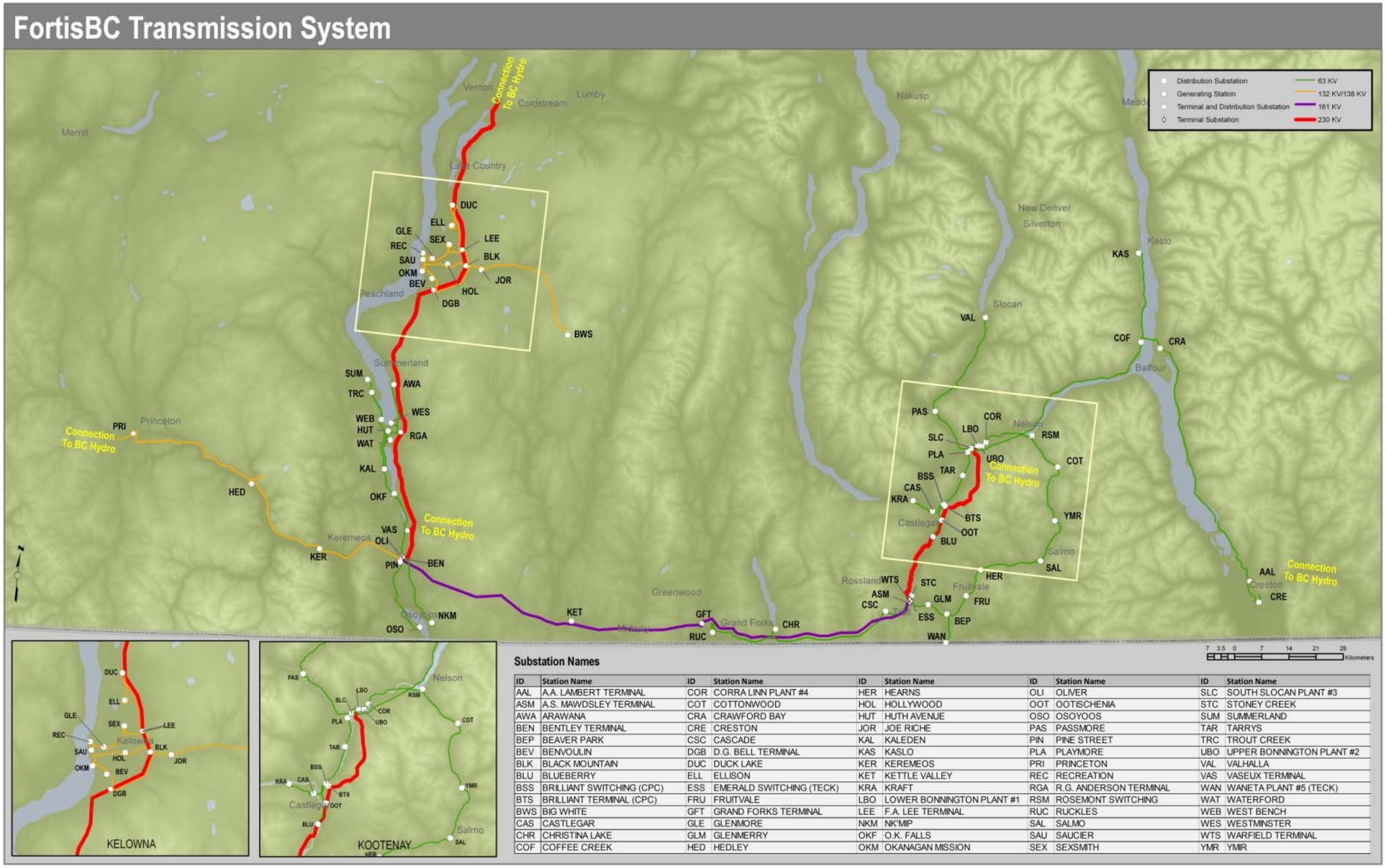
The only FortisBC-owned interconnection between the Okanagan and Kootenay networks is a single 161 kV transmission line. The FortisBC transmission system is further supported by the overlaid BC Hydro transmission grid. The FortisBC system is tied with the BC Hydro grid at five major interconnection points: Kootenay Canal Generating Station, Vaseux Lake Terminal Station, Vernon Terminal, Selkirk Substation (via Columbia Power Corporation transmission line), and the Nelway Substation (via Teck System). In addition, there are two lower capacity interconnections at Princeton and Creston which are typically only used radially to supply FortisBC load.

The two regional networks are fundamentally quite different. The Okanagan region has no generation resources and thus all demand is met by external generation delivered either directly through the FortisBC system or wheeled via the BC Hydro 500 kV network. The latter is responsible for the bulk of the transfers from the FortisBC generation to the Okanagan load centre.

The Kootenay region has a smaller load (30 percent) compared to the Okanagan region (70 percent), whereas all (100 percent) of the FortisBC-owned generation is in the Kootenay region. Additionally, the load is well distributed and thus there are fewer critical transmission paths in comparison to the Okanagan system. The following table shows an approximate breakdown of the system load and generation resources.

The complete FortisBC transmission network is shown in Figure 2.7.2 (c) below. Larger scale maps of each region are also shown in Appendix E.

1 **Figure 2.7.2 (c) - FortisBC Transmission Network**



Substation Names

ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	COR	CORRA LINN PLANT #4	HER	HEARNS	OLI	OLIVER	SLC	SOUTH SLOCAN PLANT #3
ASM	A.S. MAWDSLEY TERMINAL	COT	COTTONWOOD	HOL	HOLLYWOOD	OOT	OOTISCHENIA	STC	STONEY CREEK
AWA	ARAWANA	CRA	CRAWFORD BAY	HUT	HUTH AVENUE	OSO	OSOYOOS	SUM	SUMMERLAND
BEN	BENTLEY TERMINAL	CRE	CRESTON	JOR	JOE RICHE	PAS	PASSMORE	TAR	TARRYS
BEP	BEAVER PARK	CSC	CASCADE	KAL	KALEDEN	PIN	PINE STREET	TRC	TROUT CREEK
BEV	BENVOULIN	DGB	D.G. BELL TERMINAL	KAS	KASLO	PLA	PLAYMORE	UBO	UPPER BONNINGTON PLANT #2
BLK	BLACK MOUNTAIN	DUC	DUCK LAKE	KER	KEREMEOS	PRI	PRINCETON	VAL	VALHALLA
BLU	BLUEBERRY	ELL	ELLISON	KET	KETTLE VALLEY	REC	RECREATION	VAS	VASEUX TERMINAL
BSS	BRILLIANT SWITCHING (CPC)	ESS	EMERALD SWITCHING (TECK)	KRA	KRAFT	RGA	R.G. ANDERSON TERMINAL	WAN	WANETA PLANT #5 (TECK)
BTS	BRILLIANT TERMINAL (CPC)	FRU	FRUITVALE	LBO	LOWER BONNINGTON PLANT #1	RSM	ROSEMONT SWITCHING	WAT	WATERFORD
BWS	BIG WHITE	GFT	GRAND FORKS TERMINAL	LEE	F.A. LEE TERMINAL	RUC	RUCKLES	WEB	WEST BENCH
CAS	CASTLEGAR	GLE	GLENMORE	NKM	NK'MIP	SAL	SALMO	WES	WESTMINSTER
CHR	CHRISTINA LAKE	GLM	GLENMERRY	OKF	O.K. FALLS	SAU	SAUCIER	WTS	WARFIELD TERMINAL
COF	COFFEE CREEK	HED	HEDLEY	OKM	OKANAGAN MISSION	SEX	SEXSMITH	YMR	YMIR

2

FortisBC operates the network to supply its customers, as well as third parties requesting use of the network for their own purposes. Such parties, known as “transmission customers”, must follow the procedures, terms and conditions as defined in FortisBC’s Electric Tariff.

2.7.3 FERC ORDER 890

On February 15, 2007, the United States Federal Energy Regulatory Commission (FERC) issued its final rule, Order 890, on open access regulations, culminating a lengthy rulemaking process that began in 2005. Order 890 required all transmission providers to file significant amendments to their pro forma open access tariffs, in order to increase transparency in the rules applicable to planning and the use of the transmission system.

FERC recognized that the Open Access Transmission Tariff (OATT) was not sufficient to encourage non-discriminatory transmission expansion in an era of congestion and under-investment in the transmission grid and did not sufficiently counter the incentives for transmission owners to expand the system in a manner that favors their generation and their native load. FERC concluded that it is necessary to require coordinated, open, and transparent transmission planning on both the local and regional level. The FERC amendments included important new requirements for electric utility transmission planners. A more inclusive transmission planning process was defined incorporating nine principles:

- **Coordination -** The transmission provider must meet with all of its transmission customers and interconnected neighbors to develop a transmission plan. Meetings might be complemented by a standing planning committee. Customers must be included at the early stages of the development of the transmission plan and not merely given an opportunity to comment on transmission plans that were developed in the first instance without their input.
- **Openness -** Transmission planning meetings must be open to all affected parties and stakeholders. While some circumstances require planning efforts of smaller groups, the process must remain open.
- **Transparency -** The transmission provider is required to disclose to all customers and other stakeholders the basic criteria, assumptions, and data that underlie its planning.

- **Information exchange -** Transmission customers are required to submit information on their projected loads and resources on a comparable basis as used by transmission providers in planning for their native load at regular intervals, and the transmission provider must allow market participants the opportunity to review and comment on draft transmission plans.
- **Comparability -** The transmission system plan should meet the specific service requests of transmission customers and otherwise treat similarly situated customers comparably.
- **Dispute resolution -** Transmission providers are required to develop a dispute resolution process to manage disputes that arise from the planning process and that should address both procedural and substantive planning issues.
- **Regional participation -** The transmission provider is required to coordinate with interconnected systems to share system plans and ensure that they are simultaneously feasible and identify system enhancements that could relieve large and recurring transmission congestion.
- **Economic planning studies -** Customers should be permitted to choose the studies that are of the greatest value to them and be given the right to request a defined number of high priority studies annually, the cost of which would be recovered as a part of the overall pro forma OATT cost of service. A customer requesting the study must provide economic data in its possession. Transmission providers are not required to implement or fund economic projects.
- **Cost allocation for new projects -** Cost allocation methodologies are intended to apply to projects that do not fit under existing rate structures. There is a free rider problem with cost allocation and regional planning processes are encouraged to adopt cost allocation principles which fairly assign costs among participants, including those who cause them to be incurred and those who otherwise benefit from them.

Electric utilities and transmission organizations in Canada are not subject to FERC jurisdiction and are not required to implement FERC Order 890. However, certain Canadian organizations have modified their planning processes to voluntarily comply with those requirements of the FERC Order that are most applicable in Canada. The transmission planning group at FortisBC is reviewing the requirements vis-à-vis its existing planning process to determine the extent to which the process already meets the requirements, as well as changes in the process to incorporate those FERC requirements that are most relevant in British Columbia and most beneficial to FortisBC stakeholders.

2.7.4 TRANSMISSION PLANNING RELIABILITY STANDARDS

Reliability is a measure of the ability of the interconnected system to perform its intended function and is defined in terms of adequacy and security. Adequacy means the electric system needs to be able to supply aggregate electrical demand for customers at all times. Security means the electric system must withstand sudden disturbances or unanticipated loss of system elements.

FortisBC's electric system must comply with the BC Mandatory Reliability Standards (BC MRS). Included in these standards are a set of transmission reliability planning documents referred to as the TPL series of standards. The four standards described below are mandatory and are the foundation for transmission planning work throughout North America:

- **TPL-001** defines requirements of system performance under normal conditions with all system elements in-service (N-0 condition).
- **TPL-002** defines requirements of system performance following loss of a single bulk electric system element (N-1 condition).
- **TPL-003** defines requirements of system performance following loss of two or more bulk electric system elements (N-2 condition).
- **TPL-004** defines requirements of system performance following extreme events resulting in the loss of two or more bulk electric system elements.

The TPL standards require that the system be planned to serve all customer loads during "all elements in-service" normal operation (N-0) and single-contingency (N-1) conditions. Exceptions are allowed for customer loads supplied radially by the faulted element or by the affected area. For double contingency (N-2) and higher conditions the standards allow planned and controlled disconnection of customer loads. Special protection systems and Remedial Action Schemes may be employed during system operations to minimize the frequency and duration of customer outages.

The task of providing reliable and cost-effective electric service requires the ability to make assessments of reliability for various system configurations. FortisBC transmission planners employ both deterministic and probabilistic methods to assess system reliability. The TPL standards described above are examples of classic deterministic planning methods. In some cases, however, strictly deterministic techniques are not sufficient. The probabilistic nature of system events must also be considered in the determination of the most reliable and cost effective system plan. For example, once a transmission deficiency has been identified, the options analysis must consider factors such as the probability of the initiating contingency multiplied by the probability of being at the load level where the contingency will result in an overload or low voltage condition. Then the economic consequences of a probable customer outage must be weighed against the certain cost of adding transmission infrastructure.

2.7.5 TRANSMISSION PLANNING STUDIES

The FortisBC transmission planning group conducts system studies to ensure that the system will continue to meet reliability standards in the presence of growing customer load during the planning horizon, typically 20 years. These studies are performed annually in accordance with the requirements of the TPL standards and result in the identification of transmission system upgrades required in the short term and medium term. Additional bulk system studies are conducted, when deemed necessary, with a 30-year planning horizon. The intent of these long term studies is not necessarily to identify specific system upgrades but, rather, the system load levels at which a new set of reinforcement options must be considered.

The studies are based on load flow analysis and transient stability analysis using the power systems simulation software package PSS®E. This software is used by FortisBC and several other utilities in WECC. In the current FortisBC study cycle, the load flow analysis was carried out for years 2012, 2016 and 2020 both for winter and summer peak load conditions. In addition, load flow analysis was also performed for 2012 light load conditions. The transient stability analysis was carried out for year 2012 winter peak, summer peak and light load conditions. Longer term studies of the bulk system out to the planning horizon were also conducted to determine the need for future large transmission upgrades.

The basic premise upon which any transmission plan at FortisBC is founded is that the transmission system must be capable of supplying all customer peak load demand, under reasonably adverse weather conditions and with any single transmission system element out of service (N-1). A risk-indexed load forecast is therefore necessary to reflect “reasonably adverse weather conditions” and such a forecast is produced using the methodology described in the Company's 2012-13 Revenue Requirements application at Tab 3.

The load flow study includes an analysis of all possible single contingencies (N-1) in the FortisBC system. Thermal violations, or overloads, are recorded on elements that show a power flow exceeding 90 percent of its respective winter or summer emergency rating. Voltage violations are also recorded on system buses that show a voltage less than 90 percent or greater than 110 percent of nominal voltage. All buses at and above 63 kV in the FortisBC system and major 230 kV and 500 kV buses of the neighbouring BC Hydro and BPA systems are monitored in the study.

The transient stability study is based on simulations of three phase and single-line-to-ground faults in accordance with the TPL standards. Normal fault clearing as well as the slower back up clearing are both simulated, followed by the tripping of the faulted line. The dynamic performance of the system is assessed based on observations of post-fault behaviour of important system quantities, such as generator rotor angle, power flows, bus voltages and system frequency. Analysis of post-fault oscillations in these studies will reveal how quickly the oscillations stabilize, leading to a quick system recovery from the disturbance.

An assessment of reactive power capabilities is also necessary, as the FortisBC system consists of two areas, one with surplus generation in the Kootenays and the other with total absence of generation in the Okanagan. The lack of dynamic reactive support in the Okanagan can lead to low voltages during contingency conditions. The "reactive margin" method is employed to quantify the degree of reactive support available at critical buses in various contingency situations.

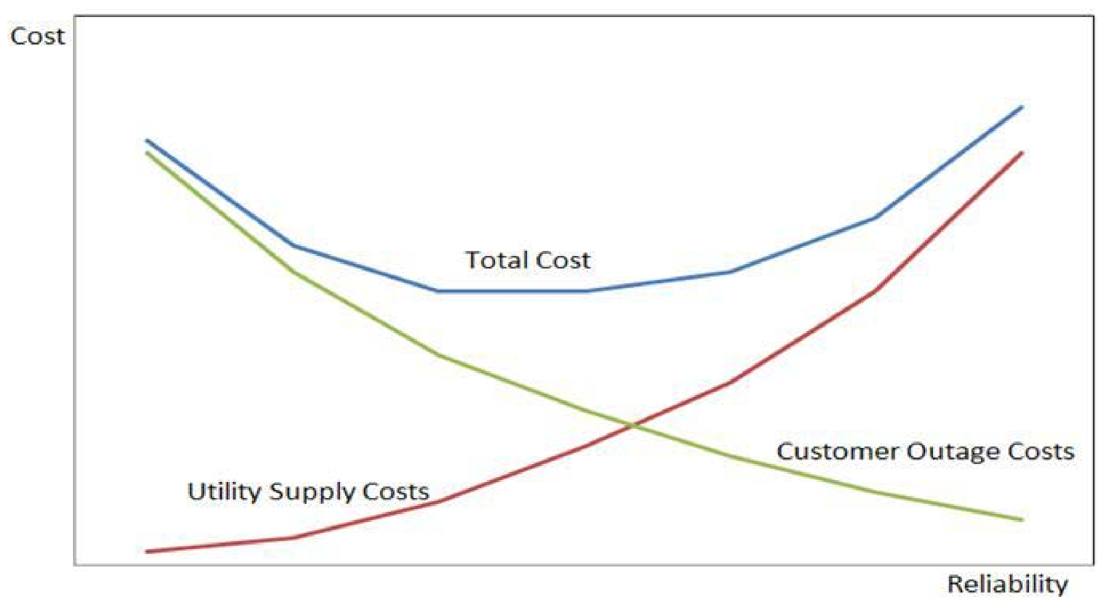
Each thermal or voltage violation found in the studies is analyzed in order to define the most cost-effective mitigation plan. The studies identified a collection of transmission reinforcement projects that are required within the 30 year planning horizon. These projects are required as the system reaches various load thresholds and are required to mitigate all violations and to ensure continuing compliance with the BC Mandatory Reliability Standards. It must be noted that the degree of timing certainty for projects is not the same throughout the planning horizon. Longer term projects will be subject to further reviews as load growth trends become more visible in the future. Furthermore, the possible location of new generating sources in the Okanagan will require a complete reassessment and may result in the elimination of certain transmission projects in the long term.

2.7.6 RELIABILITY STUDIES

The solution to a reliability violation is quite often straightforward, with only one reasonable option. In many cases, however, more than one transmission upgrade option can be developed to mitigate a given set of reliability violations. These must be assessed in order to define the most cost effective solution. Such assessment cannot be complete unless it includes, in addition to project financial costs, a consideration of reliability costs and benefits, which will generally be different for each project. The transmission planning group employs quantitative analytical methods to define the costs and benefits associated with the reliability attributes of each project.

Figure 2.7.6 (a) shows that the cost to the utility increases with increasing reliability, due to the higher capital expenditures required to provide a higher level of system reliability. The costs to customers decrease with increasing reliability, due to avoided costs of power interruptions to residential, commercial and industrial customers. The sum of these two costs will be the total cost to society. The optimum level of reliability is therefore the point where the total cost is minimized.

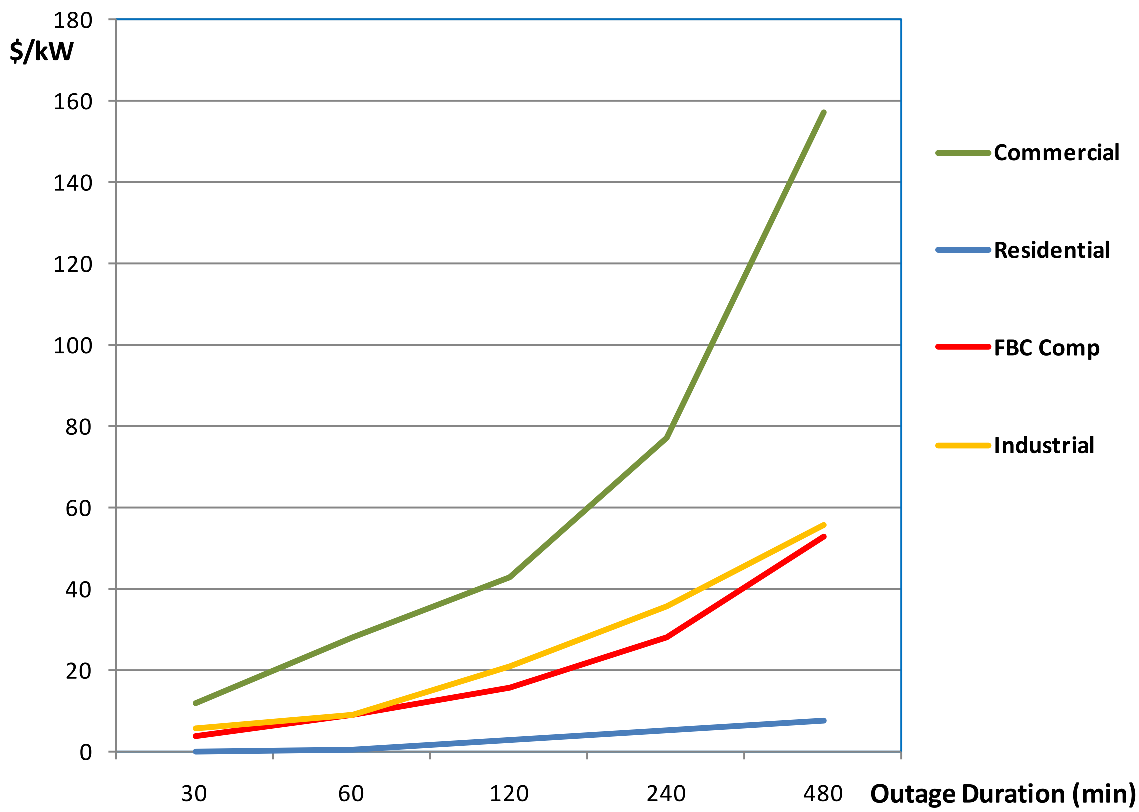
Figure 2.7.6 (a) - Cost as a Function of Reliability



Of the two components making up total cost, in Figure 2.7.6 (a), the customer outage costs are the most difficult to determine. The methodology employed at FortisBC is based on the “customer damage function” (CDF) and the end result is the “cost of energy not served”.

The CDF provides, for each customer class or predefined customer mix, the economic cost in $/kWh of a power service interruption depending on the duration of the interruption. FortisBC has developed a composite CDF based on a customer survey that was conducted across Canada by the Power System Research Group of the University of Saskatchewan with participation of seven Canadian utilities. Based on this survey a CDF was created for British Columbia, reflecting responses to the survey from British Columbia electricity customers. The commercial and industrial customer components of this CDF were modified to reflect the proportions of these components in the FortisBC customer mix and the resulting composite CDF is shown in Figure 2.7.6 (b).

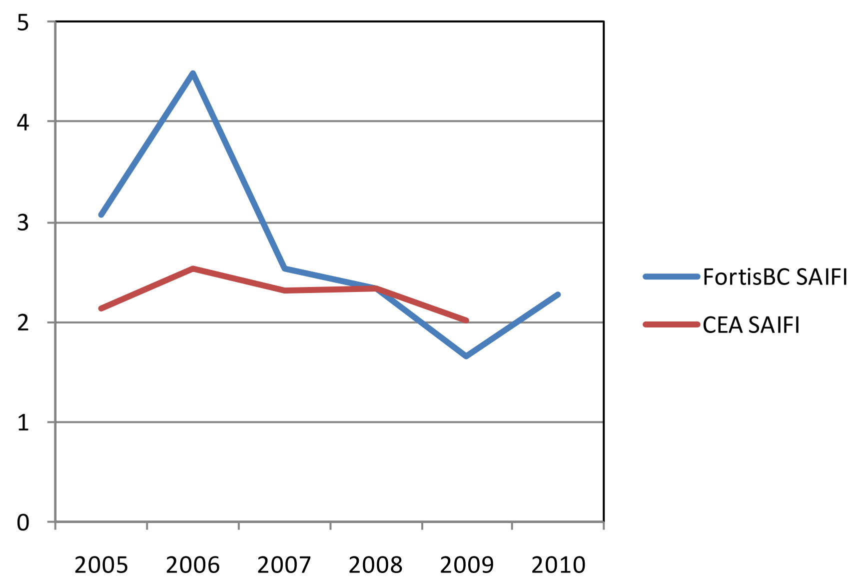
Figure 2.7.6 (b) - FortisBC Customer Damage Functions



In addition to a customer damage function, the reliability analysis tool requires input data on system topology, including customer loads, as well as outage statistics for each type of system equipment modeled. These are expressed in terms of “failure rate” in outages per year and “repair rate” in hours per outage. Extensive outage statistics are available from the Canadian Electricity Association (CEA) and from various other sources in the United States. The analytical tool performs “sequential Monte Carlo simulations” to produce an operating history of the system and provide a record of customer outages with outage durations and customer costs. The generic nature of equipment outage statistics raises the question of applicability to a specific utility. In the absence of local data, this issue is addressed with sensitivity studies that vary the input data to define a range of solution outcomes.

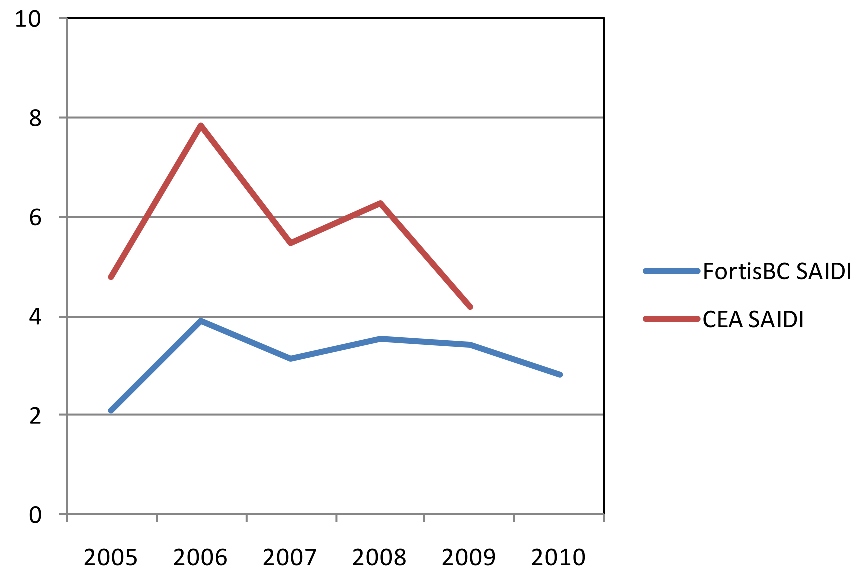
There are several other indices that are employed in the reliability analysis of the FortisBC system. For example, assessment of total system reliability performance is based on indices like the System Average Interruption Frequency Index (SAIFI) and System Average Interruption Duration Index (SAIDI). These indices can be computed analytically or computed empirically from operating statistics.

Figure 2.7.6 (c) - SAIFI for FortisBC and CEA



Note: Reported by calendar year. 2010 SAIFI totals are not available from the CEA at this time.

Figure 2.7.6 (d) - SAIDI FortisBC and CEA



Note: Reported by calendar year. 2010 SAIDI totals are not available from the CEA at this time.

Figures 2.7.6 (c) and (d) show comparisons for 2005 to 2010 between the FortisBC SAIFI and SAIDI and the CEA Canadian averages. SAIFI and SAIDI are widely used by electric utilities in Canada and the United States to measure the reliability of the energy delivery system. SAIFI and SAIDI are a function of (1) system topology, (2) operating policies, and (3) random events. These indices have in the past been computed and stated as single deterministic values. Recent studies, however, have shown that they are best described by probability distributions. When system topology and operating policies have not changed, year-over-year changes in SAIFI and SAIDI are an outcome of random events, primarily extreme weather events, and are not indicative of fundamental changes in system reliability. The method of application of the indices must therefore be improved to recognize their probabilistic nature.

2.7.7 RESOURCE PLANNING INTERRELATIONSHIP WITH TRANSMISSION

As discussed in Section 2.7.2, FortisBC's transmission system consists of two fundamentally different regions - the Okanagan and the Kootenay.

The Kootenay region can be considered as a "generation surplus" area with no identified bulk transmission system reinforcements (either capacity or reliability-driven) required within the current 30-year planning horizon. Certain upgrades required to address localized sub-transmission and distribution deficiencies are discussed in more detail below.

Conversely, the Okanagan region will face both capacity and reliability-driven constraints as the Okanagan load continues to grow. In normal operations (all transmission elements in-service) the Okanagan system is forecast to accommodate load growth until approximately the year 2027. Prior to this date, transmission reinforcement projects have been identified which are required to ensure that the FortisBC system continues to meet mandated N-1 transmission reliability standards.

For the purposes of the system studies in the Transmission and Stations portion of the System Development Plan, no additional generation resources have been assumed in the Okanagan area. However, the identified transmission projects could potentially be deferred or eliminated if firm generation resources were appropriately sited in the Okanagan area. These generation resources would have the effect of offsetting area load and thus reducing bulk transmission deliveries. A similar, but generally smaller, effect is achieved by FortisBC's demand-side management (DSM) programs. Large transmission projects that could potentially be deferred by resource additions are identified in the sections below.

2.7.8 FORTISBC TRANSMISSION CONFIGURATIONS

Following are some definitions which FortisBC uses to describe the configuration and operation of the transmission system. These configuration definitions are referenced in the project descriptions in this and other sections of the 2012 Long Term Capital Plan.

2.7.8.1 Radial configuration

This describes the configuration where a distribution substation is supplied from a single transmission source in normal operations. For example, there are a number of substations in the FortisBC system which are supplied by only a single transmission line; examples include the Summerland, Arawana, Valhalla, Waterford, and Kaslo substations. If the single transmission line supplying these stations is unavailable (either due to a planned or forced outage), then the substation will have no source of power. Stations with this supply configuration have only N-0 (all transmission elements in-service) reliability.

In some cases, a substation may have two transmission line sources, however only one supply line is used at any given time. If both transmission lines run in a common corridor, then this is generally considered a radial supply configuration (as a forced outage to both adjacent circuits is considered a credible event). Examples of these stations are the Cascade, Blueberry, Castlegar, and Ootischenia substations.

2.7.8.2 Looped configuration

This configuration describes a substation which: (a) has two or more transmission supply lines, (b) the transmission lines run in separate corridors and (c) only one of the transmission lines is used to supply the substation in normal operations. Most of FortisBC's distribution substations are configured with a looped supply.

If the normal transmission source is unavailable due to either a forced or scheduled outage, then the station can be supplied from an alternate transmission line. In many cases, this reconfiguration can be performed by remote control from the FortisBC System Control Centre. In some cases it is necessary for technicians to be dispatched to manually switch the substation to an alternate supply source.

Stations of this type have what is referred to as N-1 (single-contingency) "long-term outage" reliability. In other words, a customer outage will occur following a transmission failure; however, the problem can generally be corrected fairly quickly to restore supply. Thus, long duration outages due to the failure of a single transmission line are prevented.

2.7.8.3 Meshed configuration

This configuration is very similar to the looped configuration; however, in meshed operation the transmission supplies to a substation are normally operated in parallel. As a result, if an outage occurs to one of the transmission lines supplying a substation, then an alternate line is immediately available to provide continued supply. No manual reconfiguration of the system is necessary and no customer outages occur. This is referred to as N-1 (single-contingency) "all outages" reliability. The FortisBC bulk transmission system must meet this level of reliability in order to comply with legislated mandatory reliability standards (described above in Section 2.7.4).

Where practical and cost-effective this level of reliability has been applied to some FortisBC distribution substations. Converting a station from looped supply to meshed supply typically requires upgrades to the protection and communications systems for the transmission system. Since this can have considerable cost impacts, the capital cost of the upgrade must be weighed against the improved reliability provided by fully meshed operation.

2.8 Transmission and Stations Growth Capital Projects

Following is a listing of all potential Transmission and Stations growth projects which have been identified within the planning horizon (20 years for regional projects and 30 years for bulk system projects). The projects identified outside of the five year timeframe (2017 and beyond) are more variable in terms of timing than the projects identified in the five year timeframe (2012 to 2016). For projects identified within the five year timeframe the projects have been through a detailed planning review, options analysis, and preliminary estimation and are deemed to be necessary to continue to provide safe reliable power at the lowest reasonable cost. Cost estimation has been performed at a Class 3 level as stated in FortisBC/AACE guidelines (described in section 2.2) for projects identified in 2012-13 Capital Plan, Class 4 as stated in the guidelines for projects identified between 2014 and 2016, and Class 5 as stated the guidelines for projects identified beyond 2017. For projects beyond 2017, there has generally been no detailed options analysis done and the projects described are the best estimated solution at this time to continue to provide reliable service given the current load forecast. Depending on when and where load develops these projects may by be deferred or advanced in time, or in some cases may no longer be required during the current planning horizon.

1 **Table 2.8 (a) - Transmission and Stations Projects**

	Transmission Growth	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Okanagan Transmission Reinforcement	2,219	-	-	-	-	-
2	Ellison to Sexsmith Transmission Tie	7,121	413	-	-	-	-
3	Grand Forks Transformer Addition	2,491	4,714	1,274	7,549	-	-
4	Kelowna Bulk Transformer Capacity Addition	-	3,720	10,832	11,014	-	-
5	42 Line Meshed Operation (Huth and Oliver)	-	-	278	-	-	-
6	Capacitors at Bentley Terminal	-	-	-	875	4,389	-
7	Reconductor 52 Line and 53 Line	-	-	-	875	1,479	4,403
8	Meshing Kelowna Loop	-	-	2,753	2,798	2,577	-
9	Summerland Substation Transformer Upgrade	-	-	2,152	4,427	-	-
10	Beaver Valley Solution	-	-	-	-	758	20,776
11	RG Anderson Distribution Transformer Upgrade	-	-	-	-	3,031	4,061
12	DG Bell Static VAR Compensator	-	-	-	-	3,031	34,285
13	DG Bell 230 kV Ring Bus	-	-	-	-	-	35,383
14	DG Bell Second 230/138kV Transformer	-	-	-	-	-	18,746
15	Vaseux Lake Third 500/230kV Transformer	-	-	-	-	-	31,581
16	Boundary Area Supply	-	-	-	-	-	9,629
17	Reconductor 31 Line (Creston Area)	-	-	-	-	-	2,307
18	Stoney Creek Second Distribution Transformer Addition	-	-	-	-	-	17,328
19	Playmor 25 kV Distribution Transformer Addition	-	-	-	-	-	15,612
20	Reconductor 50 Line (Recreation to Saucier)	-	-	-	-	-	295
21	Reconductor 50 Line (FA Lee to Springfield Tap)	-	-	-	-	-	-
22	Reconductor 51 Line and 60 Line (DG Bell to OK Mission)	-	-	-	-	-	9,184
23	Reconductor 54 Line (DG Bell to Black Mountain)	-	-	-	-	-	-
24	FA Lee Distribution Transformer Addition	-	-	-	-	-	12,029
25	New Enterprise Substation	-	-	-	-	-	35,798
26	Sexsmith Second Distribution Transformer Addition	-	-	-	-	-	9,377
27	Saucier Second Distribution Transformer Addition	-	-	-	-	-	7,415
28	Benvoulin Second Distribution Transformer Addition	-	-	-	-	-	11,752
29	Ellison Second Distribution Transformer Addition	-	-	-	-	-	7,850
30	DG Bell Second Distribution Transformer Addition	-	-	-	-	-	10,041
31	New Central Okanagan Station	-	-	-	-	-	37,004
32	Creston Area Capacity Increase	-	-	-	-	-	14,017
33	**Total Transmission Growth**	**11,832**	**8,847**	**17,287**	**27,537**	**15,265**	**348,873**

1 **Table 2.8 (a) - Transmission and Stations Projects cont'd**

	Transmission Sustainment	**2012**	**2013**	**2014**	**2015**	**2016**	**2017-31**
		($000s)					
34	Transmission Line Condition Assessment	522	485	480	547	543	10,216
35	Transmission Line Rehabilitation	3,372	2,621	2,509	2,424	2,820	50,158
36	Transmission Line Urgent Repairs	594	620	616	622	661	11,543
37	Transmission Line Right of Way Easements	400	400	416	423	440	7,754
38	6 Line /26 Line River Crossing Reconfiguration	1,185	-	-	-	-	-
39	27 Line Rebuild (Corra Linn-Salmo)	1,161	-	-	-	-	-
40	21-24 Lines Rebuild (Generation Plants)	2,219	-	-	-	-	-
41	19 Line/29 Line Reconfiguration	-	791	-	-	-	-
42	20 Line Rebuild (Warfield Terminal-Salmo)	-	4,664	-	-	-	-
43	30 Line Lake Crossing Assessment and Rehabilitation	-	-	-	802	1,521	-
44	**Total Transmission Sustainment**	**9,453**	**9,581**	**4,021**	**4,818**	**5,984**	**79,671**
45							
46	**Stations Sustainment**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017-31**
47	Environmental Compliance (PCB Mitigation)	11,269	11,553	4,574	-	-	-
48	Station Urgent Repairs	818	907	879	977	942	17,065
49	Station Assessment/Minor Planned Projects	1,343	1,354	1,410	1,433	1,489	26,245
50	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	566	1,140	1,184	-
51	Huth Low Voltage Breaker Replacement (2)	-	69	550	-	-	-
52	Switchgear Replacement Program (13 kV)	-	-	1,651	-	983	2,651
53	Ground Grid Upgrades	-	-	748	-	790	6,403
54	DG Bell 138 kV Breaker and Voltage Transformer Addition	-	-	338	938	-	-
55	Osoyoos 63 kV Breaker Additions (2)	-	-	-	364	2,359	-
56	Bulk Oil Breaker Replacements	-	-	-	733	761	2,972
57	Station Oil Containment	-	-	-	445	462	2,664
58	Minimum Oil Circuit Breaker Replacement	-	-	-	-	-	21,175
59	Major Transmission Transformer Replacements	-	-	-	-	-	32,017
60	Distribution Transformer Replacements	-	-	-	-	-	10,978
61	**Stations Sustainment Total**	**13,969**	**14,427**	**10,716**	**6,030**	**8,970**	**122,170**
62							
63	**Total Transmission and Stations Projects**	**35,255**	**32,854**	**32,024**	**38,385**	**30,220**	**550,714**

2.8.1 OKANAGAN TRANSMISSION REINFORCEMENT PROJECT (OTR)

The OTR Project was approved by Commission Order C-5-08. To allow independent switching of the FortisBC 230 kV transformers, BC Hydro is required to install a new 500 kV circuit breaker on the BC Hydro 500 kV side of the station with associated protection and control changes. BC Hydro has submitted its project plan for this required work, with the scheduled in-service date delayed from the fall of 2011 to summer 2012. This delay resulted from extended discussion and negotiations with respect to BC Hydro cost estimates and management. FortisBC signed off the facilities agreement at the end of February 2011 to secure the in-service date. This component of work has no material impacts to the completion of FortisBC's new and upgraded facilities.

The BC Hydro Vaseux Terminal 500 kV work will be completed in 2012 with expenditures of $2.2 million in 2012. This delay has not resulted in any total project increases. The OTR Project is forecast to be under budget.

2.8.2 ELLISON TO SEXSMITH TRANSMISSION TIE

The Ellison and Duck Lake Substations currently are fed radially from the FA Lee Terminal station via 46 Line. A fault on this line will cause an outage to both stations. With a single transmission line into the area, it is not possible to completely restore supply until that transmission line is repaired. Additionally, there is minimal distribution backup into this area as the adjacent Sexsmith distribution source is already heavily loaded and is a long distance from the majority of the load concentration (five kilometres and greater). There are also a number of large customers in this area including the University of British Columbia Okanagan, Kelowna International Airport and Kelowna Flightcraft. These customers would be impacted by an extended outage.

The need for the Ellison to Sexsmith tie was identified in the application for a CPCN for the Ellison Substation, approved by Commission Order C-4-07, and at that time was anticipated to be constructed in 2010. In its 2009 System Development Plan Update, the Company rescheduled the transmission loop for the Sexsmith, Ellison and Duck Lake substations to the 2011 or later timeframe. With the addition of new distribution load (BC Hydro customers in the Winfield area) onto the Duck Lake Substation in 2011, a transmission outage on 46 Line will affect approximately 9,700 customers served by this line.

This project involves adding a 138 kV line termination and all associated bus work at the Ellison Substation and the construction of a 138 kV line from the Ellison Substation to a tap into 50 Line near the Sexsmith Substation.

The satellite imagery in Figure 2.8.2 (a) below shows the area where the Ellison to Sexsmith transmission tie is proposed showing the highway corridor it will follow. On the north side (top) it will pass by the airport on the west side of the highway near an industrial/commercial business park and continue south past by the university area. There is some commercial development on the south end of the line right of way where it ties in with the existing transmission line. There is a distribution line along the full proposed line route and the transmission circuit will be overbuilt on the existing 13 kV distribution line.

Figure 2.8.2 (a) - Satellite view of Ellison to Sexsmith Transmission Tie

The construction of this line segment will provide a 138 kV loop in the northern portion of Kelowna, complementing the two existing 138 kV transmission loops, thus providing N-1 transmission reliability for all areas of Kelowna.

This project will also provide the option of taking 46 Line out of service for maintenance thereby eliminating the need for using live-line procedures or taking outages on both the Duck Lake and Ellison stations when conducting maintenance work on 46 Line. Live-line work at 138 kV is more complex, costly and risky (both in terms of safety and reliability) than work involving de-energized lines.

Figure 2.8.2 (b) below shows the Kelowna area system and the proposed Ellison to Sexsmith Transmission Tie.

Figure 2.8.2 (b) - Proposed Ellison to Sexsmith Transmission Tie

In its 2011 Capital Expenditure Plan application, FortisBC sought approval for the preliminary engineering and estimating work for this project. In the decision associated with BCUC Order G-195-10 approving this expenditure, the Commission noted that: "The

Commission Panel finds that the expenditure for the Ellison to Sexsmith Transmission Tie engineering and estimating costs, required for the design phase of a project to provide increased reliability to the 9,700 customers served by this line, is in the public interest." This project is estimated to cost $7.12 million in 2012 and $0.41 million in 2013.

2.8.3 GRAND FORKS TERMINAL TRANSFORMER ADDITION AND HIGH-CAPACITY COMMUNICATIONS PROJECT

Introduction and Project Summary

The Grand Forks Terminal Transformer Addition and High-Capacity Communications project is intended to address two FortisBC system deficiencies:

1. Transmission system reliability issues for the Grand Forks area; and
2. A gap between the Okanagan and Kootenay communications systems.

There is a significant cost-saving opportunity to the benefit of FortisBC customers if the projects are considered in conjunction, rather than addressed individually and in isolation.

The full project is proposed to be constructed over four years. In 2012/13, a spare transmission transformer will be relocated and stored at the Grand Forks Terminal and a high-capacity communications fibre optic link between Grand Forks and Warfield will be constructed. In 2014/15, the transformer would be installed at the Grand Forks Terminal and aging 63 kV transmission lines between Rossland and Christina Lake would then be salvaged.

Presently, FortisBC is only seeking approval for expenditures related to the relocation and storage of the transformer at the Grand Forks Terminal and for the construction of the fibre optic link between Grand Forks and Warfield. Approval for expenditures related to the installation of the transformer (and construction of associated substation works) as well as the salvage costs for the 63 kV transmission lines will be the subject of a future Capital Expenditure Plan application (currently proposed for 2014/15).

The following sections discuss the two system deficiencies in detail. An options analysis leading to the proposed project solution is then presented.

Grand Forks Area Transmission Limitations

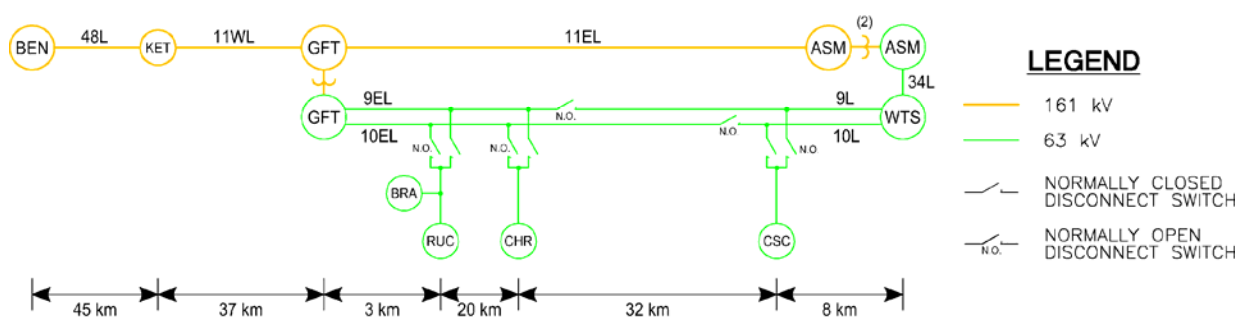
The Grand Forks Terminal is a major substation which provides the normal transmission supply for Grand Forks, Christina Lake and surrounding areas. The station is supplied at

161 kV both from Warfield (via the AS Mawdsley Terminal) and from Oliver (via the Bentley Terminal) and thus has full single-contingency (N-1) reliability from a 161 kV bulk supply perspective. The 161 kV voltage is stepped-down to 63 kV via a single 161/63 kV transformer referred to as Grand Forks Terminal T1 transformer. This transformer, which was manufactured in 1965 (i.e. 46 years old), provides a 63 kV transmission supply to the:

- Grand Forks Terminal T3 distribution transformer;
- Ruckles Substation;
- Roxul Substation (a wholesale transmission customer); and
- Christina Lake Substation.

As there is only one 161/63 kV transformer installed at the Grand Forks Terminal, a backup 63 kV source is provided via two 63 kV transmission lines which originate at the Warfield Terminal Station near Trail. This backup source is only used in the event that that T1 transformer is unavailable. Protection and communications limitations prevent the Grand Forks and Trail 63 kV systems from operating in parallel. As a consequence, the Grand Forks Terminal T1 transformer provides only a radial 63 kV supply to the area. If the transformer experiences a forced outage, then customers in the area will be without power until the system can be manually reconfigured to use the backup 63 kV supply from Trail. Figure 2.8.3 (a) below shows the current transmission configuration in the Grand Forks area.

Figure 2.8.3 (a) - Existing (2011) Boundary / Grand Forks Area Transmission System



In the normal operating configuration the Grand Forks Terminal T1 transformer supplies approximately 3,500 direct FortisBC customers. The Ruckles Substation is also a distribution wholesale supply point to the City of Grand Forks municipal utility and serves approximately 740 indirect customers. Thus, at winter peak, the Grand Forks Terminal T1 transformer supplies over 40 MW of load and a total of over 4,200 customers.

As described above, the T1 transformer is backed-up via two 63 kV transmission circuits (9 and 10 Lines) from Warfield. If the transformer is out of service for an extended period due to either a planned or forced outage, then the Grand Forks area load must be supplied from these two lines. Since an internal failure could potentially result in the T1 transformer being unavailable for a year or more, the two 63 kV circuits must currently be maintained such that they are available to reliably supply the Grand Forks area for an extended period.

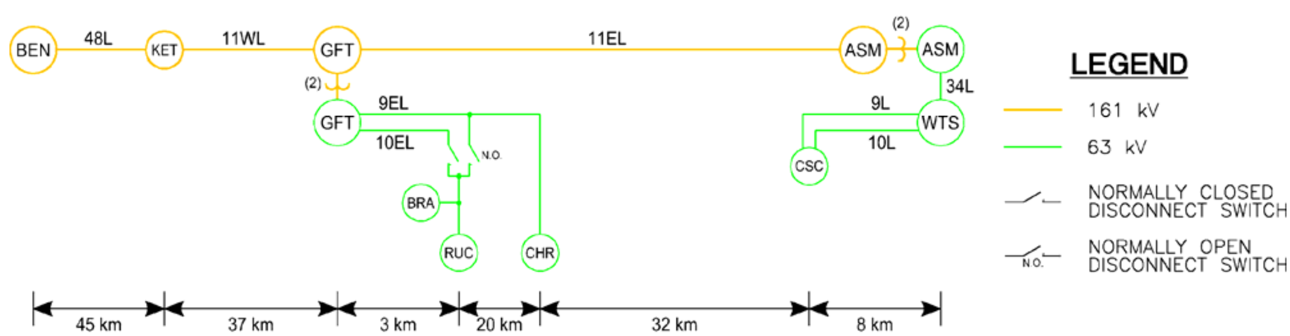
These transmission lines were originally built in 1918 and much of the construction between Rossland and Christina Lake still consists of the original poles and wire infrastructure. The two lines run in a common right of way for approximately 32 kilometers over the Rossland Range of the Monashee Mountains and thus the majority of the line route exceeds 1,000 metres in elevation. Due to the high elevation, harsh terrain and exposure to trees, the lines experience frequent (1 to 3 outages per month) and occasionally long duration (1 day or more) outages particularly during the winter season due to snow unloading and tree contacts. This compares to FortisBC's average 63 kV transmission line outage rate of 2.1 outages per year (for 2010). In the summer, the high elevation makes the lines a frequent target of lightning-caused outages. Access to the right of way for maintenance and repairs is poor. In the winter, there are significant periods where the lines can only be accessed via snowmobile, snow-cat or helicopter. Additionally, the lines parallel an underground high-pressure natural gas line; crossing the pipeline right of way with heavy vehicles (such as a line truck) requires special permits and/or temporary bridges. Finally, both circuits also have distribution underbuild and there have been occurrences where transmission-to-distribution contacts have resulted in damage to customer equipment due to overvoltage events.

These lines have not undergone condition assessment since the early 2000s and the most recent rehabilitation work was undertaken in 2005. At that time approximately 140 of 1,600 structures were repaired, replaced or stubbed. Given the age, condition and historical reliability of the lines, FortisBC expects that a significant amount (30 to 50 percent) of the lines will require rebuilding in the near future. This represents approximately 20 to 30 km of 63 kV transmission line salvage and construction in a remote area.

However, simply rebuilding the lines within the existing right of way does not resolve most issues described above. The elevation, terrain, weather, and presence of distribution underbuild would continue to negatively impact ongoing operational/capital costs, reliability and safety and thus the Company considered alternate transmission reinforcement solutions.

A practical alternate solution would be to install a second 161/63 kV transformer T2 at the Grand Forks Terminal. The station was originally laid-out for this second transformer; thus, no new land acquisition would be required and all construction would be contained within the existing fence-line. Rather than purchasing a new transformer, a 60 MVA 161/63 kV transformer recently removed from the Oliver Terminal as part of the Okanagan Transmission Reinforcement project could be reused. The ex-Oliver unit is very similar to the existing Grand Forks Terminal T1 transformer and would make parallel operation of the two transformers feasible. Installation of this second transformer would provide the Grand Forks area 63 kV transmission system with both full N-1 reliability and sufficient capacity out to (and beyond) the planning horizon. Finally, the presence of the second transformer would remove the need to maintain a 63 kV backup supply from Warfield. This would allow the salvage of approximately 64 km (approximately 830 structures) of aging transmission line between Rossland and Christina Lake. This would reduce the line length exposed to faults and requiring ongoing maintenance by over 50 percent. The final proposed configuration is shown in Figure 2.8.3 (b) below.

Figure 2.8.3 (b) - Proposed (2015) Boundary / Grand Forks Area Transmission System



Further comparison of the line rebuild versus the transformer installation options is discussed in the Options Analysis and Recommendation sections below.

Okanagan / Kootenay Communication System Limitations

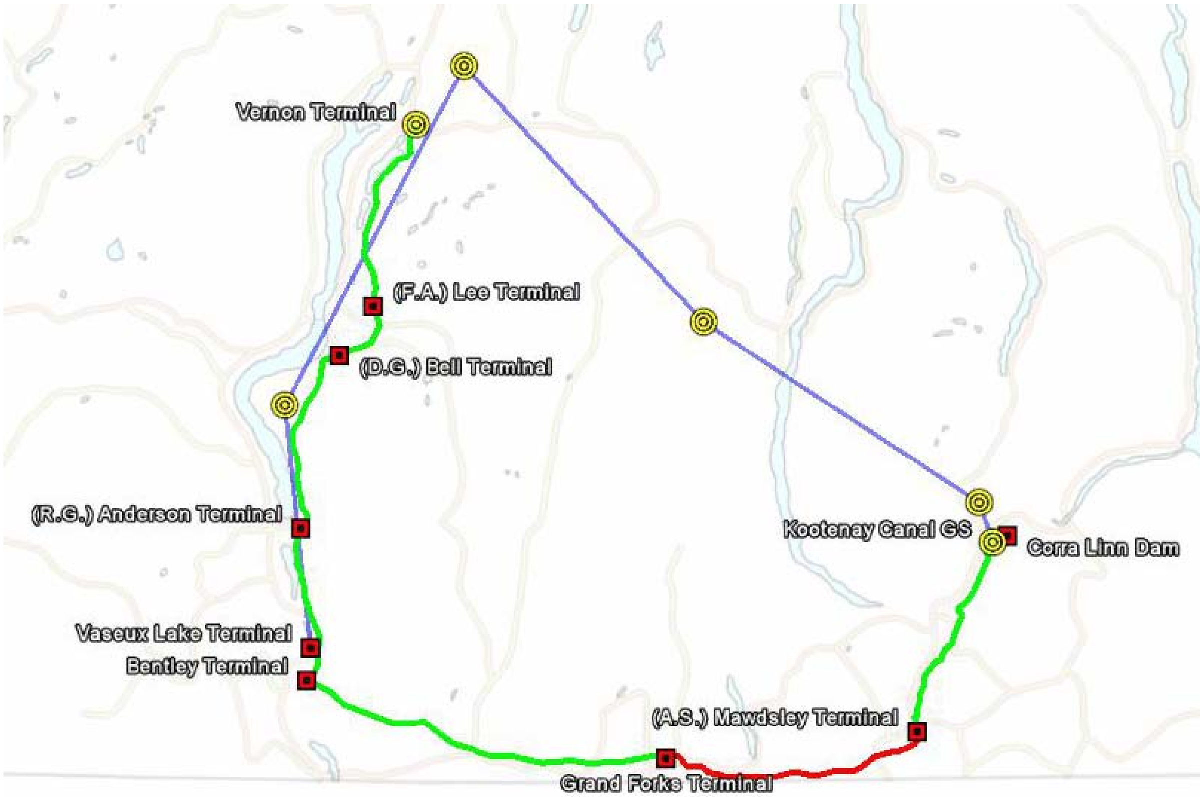
FortisBC operates two high-capacity fibre-optic backbones, one in the Kootenays and one in the Okanagan. These backbone networks are used to carry critical operational traffic such as teleprotection signaling, Remedial Action Scheme (RAS) communications, SCADA monitoring/control data, and voice communications circuits. As a secondary function, these fibre backbones are also used to provide low-cost yet high-bandwidth data communications between offices and substations for corporate wide-area network (WAN) purposes.

Presently, there is a gap between the two backbones as there is no fibre optic cable installed between Grand Forks and Warfield. This gap between the fibre backbones is currently mitigated by the use of leased communications from TELUS (for WAN purposes) and by a small number of data channels provided by the BC Hydro microwave system (for operational purposes). In the case of the WAN leased circuits, there is an approximate $50,000 per year operational cost associated with this service. In the case of the operational circuits, the bandwidth offered by BC Hydro is barely sufficient for present operational circuits and there is no additional capacity to accommodate future growth.

FortisBC's System Control Centre (SCC) is connected to the Kootenay fibre backbone, while the majority (approximately two thirds) of the Company load is located in the Okanagan, Similkameen and Boundary regions which are interconnected via the Okanagan fibre backbone. As a result, the Company is currently completely dependent on third-party providers for operational communications between the SCC and the supply substations in the most populous portion of the service territory. Extended length (2 hours or more) failures of the third-party communications systems have occurred on a regular (multiple times per year) basis and these communications outages directly impact the ability of the SCC to safely and reliably operate the interconnected system. In comparison, FortisBC's fibre-optic systems have a historical reliability approaching 99.9999 percent (less than one minute of outage per year).

Figure 2.8.3 (c) shows the existing fibre backbones (in green), the gap between the two systems (in red) and the existing BC Hydro low-speed leased circuits (in blue).

Figure 2.8.3 (c) - FortisBC Communications Backbone Infrastructure



FortisBC has entered into a binding agreement with a third-party communications provider who has committed to a long-term lease of a significant number of fibres along this route. The ongoing annual revenue resulting from this agreement benefits FortisBC customers as this Other Income goes directly to reducing revenue requirements.

The installation of fibre-optic communications between Grand Forks and Warfield can also be used to offset substation infrastructure which would otherwise be required to support the addition of the Grand Forks Terminal T2 transformer proposed above. The high-speed, dependable, and secure communications from Grand Forks to the Kettle Valley substation and AS Mawdsley substations would allow a reduction from a full four-breaker ring bus to a simpler single-breaker option on the 161 kV portion of the station. A similar arrangement was justified and constructed as part of the FortisBC Kettle Valley Substation project. This reduction in station equipment is not possible if the fibre-optic link between Grand Forks and Warfield is not constructed. For this reason, FortisBC has linked these projects together in order to fully represent the costs and benefits of the fibre construction along with the transformer addition.

In order to fully consider the total costs to mitigate both the transmission reliability issues in Grand Forks and the lack of high-capacity communications between the Okanagan and Kootenay regions, three options were identified:

- Option 1: Construct a high-capacity fibre link between Grand Forks and Warfield in 2012/13 and install Grand Forks Terminal T2 transformer with a minimal-bus arrangement in 2014/15.
- Option 2: Install Grand Forks Terminal T2 transformer with a full ring-bus in 2014/15 and continue to rely on third-party communications between Okanagan and Kootenays.
- Option 3: Rebuild 9L/10L over a period of years (2014-17 proposed) and continue to rely on third-party communications between Okanagan and Kootenays

FortisBC has not proposed a "Do nothing" option as it is not considered financially prudent or Good Utility Practice. As discussed previously, given the age, condition and historical reliability of 9 and 10 Lines, the Company expects that large portions of these lines will require rehabilitation/rebuilding in the near to medium-term. If the required expenditures are deferred, then the ongoing risks associated with transmission line failures such as long-duration customer outages, potential public and environmental safety risks and potential customer over-voltages due to transmission to distribution contacts will be incurred for longer than necessary. As a result, a significant amount of capital expenditures are inevitable in order to mitigate these risks.

Additionally, at some point, the necessity for a high-capacity communications link between the Okanagan and Kootenay fibre-optic systems will become mandatory. This will occur either due to BC MRS compliance requirements, the need for additional bandwidth to support future Smart Grid projects, for reliability/operational reasons or to reduce ongoing leased communications costs.

Table 2.8.3 - Comparison of Benefits by Option

Benefits	Option		
	1	**2**	**3**
Provides N-1 transmission reliability for Grand Forks area	X	X	X
Minimizes substation construction at the Grand Forks terminal	X		X
Allows salvage of 9 and 10 Line between Rossland and Christina Lake	X	X	
Reduces exposure to transmission/distribution underbuild over-voltage events	X	X	
Provides high-capacity communications between Okanagan and Kootenays	X		
Reduces dependence and ongoing lease costs for third-party telecommunications	X		
Provides opportunity for additional ongoing revenue from surplus fibre leases	X		
Takes advantage of spare transformer from Oliver station	X	X	
Lowest environmental and public impact from transmission line infrastructure	X	X	

This solution provides the best long-term value to FortisBC customers as it meets the requirements of providing a reliable 63 kV transmission supply for the Grand Forks area in addition to providing a reliable, high-capacity link between the existing Okanagan and Kootenay communications networks.

This project is estimated to cost $2.49 million in 2012, $4.71 million in 2013 and an additional $8.82 million in 2014-15.

2.8.4 KELOWNA BULK TRANSFORMER CAPACITY ADDITION

The addition of a new power transformer is required to provide adequate transformation capacity to supply the Kelowna area load during single contingency (N-1) outage conditions. Customers in Kelowna and the surrounding areas are currently served by two 230/138 kV terminal stations: the FA Lee Terminal Station which contains two 168 MVA 230/138 kV transformers and the DG Bell Terminal Station which contains one 200 MVA 230/138 kV transformer.

The need for the additional capacity was identified in past transmission planning studies as being driven by Kelowna area load growth. The need, however, has been advanced with the transfer of the BC Hydro Winfield area load to the FortisBC Duck Lake substation in 2011. Previously, this load was supplied directly by BC Hydro via a 69 kV radial transmission line from BC Hydro’s Vernon Terminal. This transmission line and associated substation facilities were faced with imminent capacity and condition-related issues. A number of project alternatives were considered by BC Hydro to resolve the Winfield supply issue, with the recommended alternative being to expand the existing FortisBC Duck Lake substation to provide a 25 kV distribution supply to BC Hydro customers. This arrangement was formally identified in the Duck Lake Wheeling Agreement and was approved by the Commission in Order G-19-10. In the Wheeling Agreement it was identified that the joint FortisBC / BC Hydro solution would provide greater reliability for BC Hydro customers compared to a BC Hydro network upgrade solution. The Duck Lake upgrade also minimized environmental and social impacts by using existing transmission and substation facilities. From a financial perspective, BC Hydro customers were cost-neutral compared to a BC Hydro-only system upgrade, while FortisBC customers would benefit from the rate mitigation provided by the ongoing wheeling revenue. On that basis, the Wheeling Agreement satisfied the direction from the BC Utilities Commission for BC Hydro to find a solution which benefits both utilities.

Table 2.8.4 below shows the transformer loadings for all relevant contingencies, as determined by power flow simulation studies. Following the outage of one of the two existing FA Lee Terminal transformers, the load on the remaining transformer exceeds its emergency overload rating when the total Kelowna area load reaches 369 MW. This condition constitutes a violation of BC Mandatory Reliability Standard TPL-002, which requires that applicable thermal ratings are not exceeded following the loss of a single element. The standard requires that corrective plans must be implemented to eliminate the violation. In the 2012-15 timeframe the overloads can be mitigated by reconfiguring the Kelowna transmission system during peak load conditions. This is performed by moving normally-open switching points in the Kelowna 138 kV transmission system to transfer load from the FA Lee Terminal to the DG Bell Terminal.

This system reconfiguration is not effective beyond 2014-15, as the supply from DG Bell is removed for an outage of 73 Line, which at that time becomes the critical contingency. Mitigation will, therefore, require one of the options described below and must be implemented before winter 2015-16.

Table 2.8.4 - Kelowna Transformation Capacity - Load Flow Analysis

KELOWNA WINTER PEAK LOAD (MW)	CONDITION	YEAR (WINTER)	POWER FLOW IN % OF NORMAL OR EMERGENCY RATING		
			LEE		DGB
			T3	T4	T2
	All elements in-service		81	79	55
369	LEE T3 out	2012-13	-	101	59
	DGB T2 out		86	85	-
	73L out (RGA-LEE)		90	89	-
	All elements in-service		84	83	57
384	LEE T3 out	2013-14	-	106	61
	DGB T2 out		90	89	-
	73L out (RGA-LEE)		96	95	-
	All elements in-service		84	82	66
395	LEE T3 out	2014-15	-	103	69
	DGB T2 out		94	93	-
	73L out (RGA-LEE)		100	100	-
	All elements in-service		86	85	67
407	LEE T3 out	2015-16	-	106	70
	DGB T2 out		96	96	-
	73L out (RGA-LEE)		104	104	-
	All elements in-service		89	89	67
417	LEE T3 out	2016-17	-	110	72
	DGB T2 out		99	99	-
	73L out (RGA-LEE)		108	108	-

The following viable mitigation options have been identified and are currently being assessed in preparation for an application for a Certificate of Public Convenience and Necessity (CPCN) to be filed in early 2012:

1. Install a third 230/138 kV transformer at the FA Lee Terminal.
2. Install a second 230/138 kV transformer at the DG Bell Terminal.
3. Install a new 230/138 kV transformer on a new property adjacent to the existing Duck Lake substation.

In the early screening stage three additional alternatives were identified and deemed not feasible. Options considered and rejected were;

- A do nothing approach was considered and rejected. There are two reasons why this is not a viable option. First, compliance with BC Mandatory Reliability Standard TPL-002 is required and thus the project is deemed to be non-discretionary. Second, a shortage of bulk transformer capacity could cause potentially lengthy customer outages during peak and near-peak winter conditions, resulting in a level of customer service which is well below established standards.
- The option to install firm generation resources near Kelowna connected to the 138 kV transmission system was considered and rejected. This option would significantly reduce the loads of the existing transformers at the FA Lee and DG Bell Terminals and would eliminate the need to add new transformer capacity for several years. However, due to its high cost this option would be viable only if the generation were also required to meet resource planning needs. Due to the additional capacity which FortisBC will acquire through the Waneta Expansion Capacity Purchase Agreement there is no requirement for additional capacity resources, at least not in the 2014-15 timeframe. Compared to the estimated cost of a transformer capacity addition, the cost of a generation resource option is prohibitive, as it is estimated at $44 million for 39 MW of gas fired generation. The amount of generation required to make this option equivalent to the proposed solution is approximately 227 MW, equal to the emergency rating of the proposed transformer. The cost far exceeds that of the proposed solution and this option is dismissed.
- Install a new 230/138 kv transformer adjacent to Black Mountain substation. This option is electrically equivalent to Option 2 above. However, the land needed to accommodate the substation expansion is contained within the Agricultural Land Reserve (ALR). This option is dismissed as it does not offer any system performance advantages over option 5, and also has the additional uncertainty related to removal of the required lands from the ALR.

At this time FortisBC is forecasting expenditures of $3.7 million in 2013, $10.8 million in 2014, and $11.0 million in 2015 in order to meet the required project in-service date of winter 2015/16.

2.8.5 SOUTH OKANAGAN AREA UPGRADE

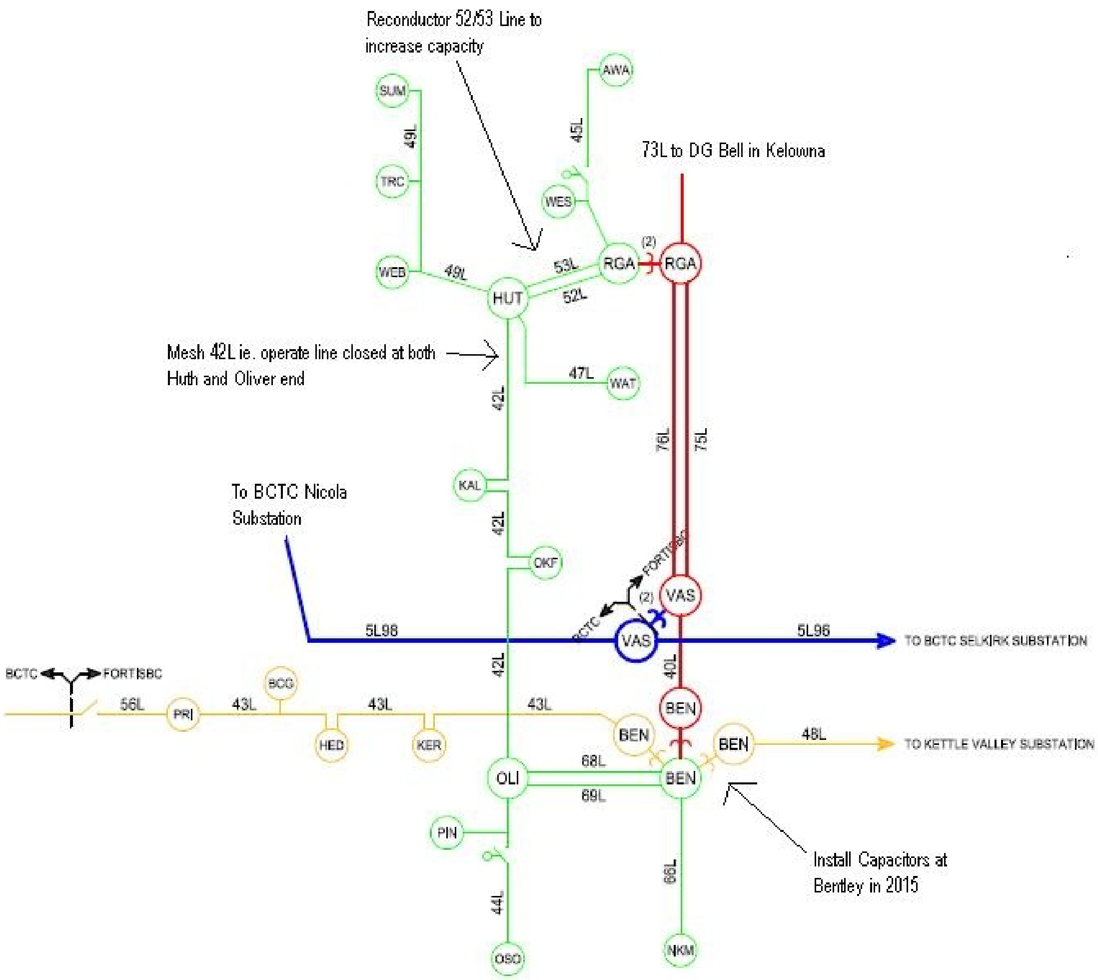
The bulk transmission supply to customers in the South Okanagan and Boundary areas is provided by a 161 kV line (48 Line) from the Kootenay region, a 230 kV line (40 Line) from

Vaseux Lake Terminal station, and a 63 kV line (42 Line) from the RG Anderson Terminal in Penticton. Load in this area can also be served via a 138 kV line from Princeton (43 Line) which ultimately interconnects with a BC Hydro transmission line. In normal operations, however, the BC Hydro interconnection is reserved as a backup supply and the interconnection point is normally open, meaning no electricity is flowing from the BC Hydro system to the FortisBC. As a result the entire load being supplied via 43 Line in the Similkameen area contributes to the load on 48 Line and 40 Line.

At the present time, Huth substation in Penticton is connected to the RG Anderson substation in Penticton via lines 52 Line and 53 Line, and to Oliver Substation in the south via line 42 Line. Approximately 50,000 residents are served through the Huth substation which feeds three substations connected to it via line 49 Line, one substation connected via line 47 Line, and another two substations connected via line 42 Line. Figure 2.8.5 below shows how the south Okanagan system is configured and where the following projects are proposed relative to each other.

The South Okanagan Area Upgrade consists of the 42 Line meshed operations project, the capacitor addition at Bentley Terminal project and the reconductoring of 52 and 53 Lines for a total $12.30 million over the 2014 - 18 timeframe with an in-service date of 2018.

Figure 2.8.5 - South Okanagan/Similkameen area Transmission System



There are three related projects scheduled to address reliability and capacity concerns in the South Okanagan area over the next 20 years. The completion of these projects will ensure FortisBC maintains compliance with BC Mandatory Reliability Standards, and continues to meet the growing capacity demands.

2.8.5.1 42 Line Meshed Operation (Huth to Oliver)

This project involves the installation of necessary protection and communication facilities to enable the meshed operation of the existing 42 Line between Huth and Oliver terminals. The purpose is to mitigate the potential of a voltage collapse in the Oliver and Boundary areas in the event of an outage of 40 Line or the Bentley T1 transformer during peak conditions. Without the supply reinforcement provided by the projects below, to prevent a voltage collapse in the event of an outage of 40 Line or Bentley T1 transformer, a Remedial Action Scheme is required to shed load in the Oliver area. This project is estimated to cost $0.28 million in 2014.

2.8.5.2 Capacitors at Bentley Terminal

This project involves the installation of reactive compensation equipment at the Bentley Terminal station. It is the second stage of the plan to prevent voltage collapse for single-contingency conditions in the Oliver and Boundary regions. The installation of additional reactive support at the Bentley Terminal combined with the ability to transfer 43 Line load to BC Hydro supply during peak loading periods mitigates the conditions that would cause a voltage collapse. The project involves the installation of 20 MVar 63 kV capacitor bank into the new constructed Bentley Terminal. The station was designed to accommodate the installation of this capacitor bank and no expansion of the station property boundary is contemplated. In combination with the completion of meshing 42 Line, it eliminates load loss in the Oliver area over the next 20 years under single-contingency conditions. This project is estimated to cost $0.88 million in 2015 and $4.39 million in 2016.

2.8.5.3 Reconductor 52 Line and 53 Line

As the load in the South Okanagan area continues to grow, eventually a thermal overload condition on either 52 Line or 53 Line will occur following an outage on either of these lines. This project involves the reconductoring of the existing 52 and 53 Lines between the Huth and RG Anderson substations with a higher ampacity conductor.

Each line is approximately four kilometres long and currently is equipped with 477 kcmil ASC conductor. The proposed conductor to achieve the required ampacity is 1,272 kcmil ASC conductor. Due to the increase in conductor size and weight both lines will essential need to be fully rebuilt to accommodate the increased structural loading from the larger conductor. Although this upgrade will require new pole structures it is anticipated that each line will be rebuilt with the existing line corridor and right of way. This project is estimated to cost $0.88 million in 2015, $1.48 million in 2016, $2.29 million in 2017 and $2.11 million in 2018.

2.8.5.4 Development Schedule and Option Analysis

Two development scenarios and timelines were considered for these three interrelated projects.

The original planned sequence of completing these three projects envisioned the reconductoring of 52 Line and 53 Line by 2013 with the other projects following soon after. This schedule is shown as Option B in Table 2.8.5.4 below. However, during the preliminary engineering investigations for the reconductoring project a number of technical issues were identified. These included construction through a riparian zone, construction through First Nations (Penticton Indian Band) property, and the existing City of Penticton distribution underbuild.

Table 2.8.5.4 - Project Planned Completion Dates

Project	Option A development schedule	Option B development schedule
42 Line Meshed Operation	2014	2014
Install Capacitors at Bentley	2015	2015
Reconductor 52 and 53 Lines	2017+	2013

As a result of these possible complications, an alternate scenario which deferred the reconductoring project and advanced the 42 Line Meshed Operation project was developed. This was supported by the revised distribution load forecast which showed lower peak load projections than previously forecast. Load flow studies confirmed that if the meshing of 42 Line was completed first, the loading on 52 Line and 53 Line during single contingency conditions would remain within acceptable limits until 2019. The cost and complexity of meshing 42 Line is also less than reconductoring 52 Line and 53 Line.

The completion of the above three projects will ensure FortisBC maintains continuous compliance with BC Mandatory Reliability Standards, and continues to meet growing capacity needs for approximately 20 years.

In the 30-year timeframe, there are two subsequent projects which have been identified. Their timing will be dependent on load growth in the South Okanagan area. These plans include the installation of a second 230 kV/63 kV transformer at the Bentley Terminal station, and construction of a second 230 kV transmission line connecting Vaseux Lake Terminal station to Bentley Terminal station.

As discussed in Section 2.8.5, these projects are reliability driven and are dependent on the South Okanagan area load. If this load was offset by the addition of appropriately-sited generation resources within the region, then the N-1 overload would be deferred or eliminated.

2.8.6 MESHING KELOWNA LOOP

Presently the Kelowna 138 kV transmission system is operated with normally open points. This operating configuration can result in widespread and lengthy outages following a single contingency. The proposed solution is to operate the system meshed but in order to do that there will need to be some upgrades to the communication and protection system on the transmission lines. This project is planned to be staged over the next five years.

The first stage is to install fiber-optic multiplexing equipment at seven substations for SCADA, voice and teleprotection communications which are planned to take place in 2012/13. The second stage is to install protection relays and perform necessary station modifications to allow the Kelowna 138 kV transmission system to be operated fully meshed. This will be staged over the 2014 to 2016 timeframe.

This project is estimated to cost $2.75 million in 2014, $2.80 million in 2015 and $2.58 million in 2016 with an in-service date of 2017.

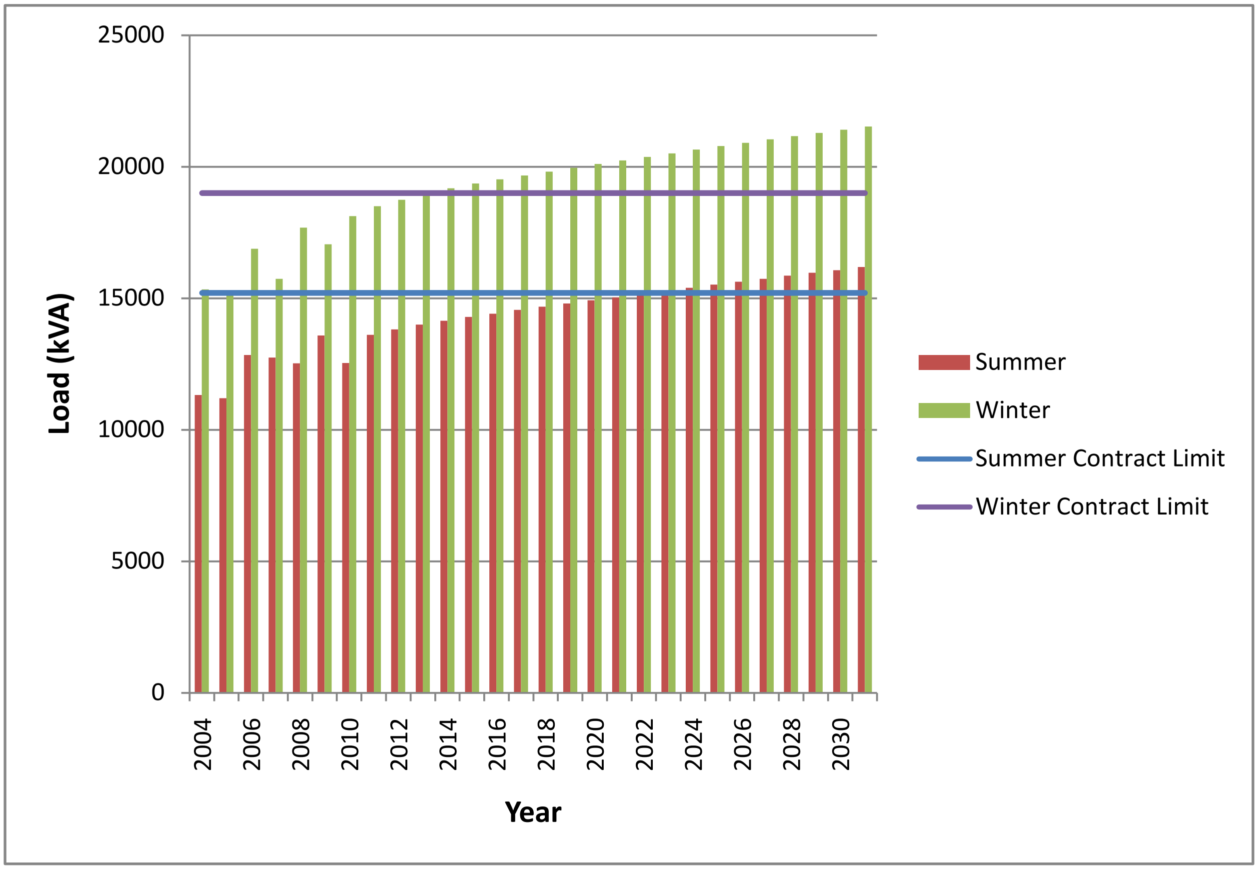
2.8.7 SUMMERLAND SUBSTATION TRANSFORMER UPGRADE

The Summerland Substation transformer is used to supply the District of Summerland municipal utility with a distribution wholesale supply. The load on the existing Summerland T1 transformer is forecast to exceed 95 percent of the contract Demand Limit in 2015. Under the terms of the wholesale supply agreement, FortisBC would be required to upgrade the supply capacity in order to continue to provide reliable service. It is proposed to replace the existing 20 MVA unit with the next larger FortisBC standard transformer which would be rated at 40 MVA. Forecasts indicate that this capacity would remain adequate out to the 20 year planning horizon.

The following graph Figure 2.8.7 illustrates the historical and forecast load for both summer and winter to the year 2031. The 95 percent threshold of the summer and winter contract demand limit (15.2 MVA and 19 MVA respectively) is also shown. The graph illustrates the violation of the 95 percent demand limit in 2015 for winter and 2025 for summer loads.

This project is estimated to cost $6.58 million ($2.15 million in 2014 and $4.43 million in 2015) with an in-service date of 2016.

Figure 2.8.7 - Summerland Forecast Load Growth



2.8.8 BEAVER VALLEY SOUTH SOLUTION

The Beaver Valley region includes the load supplied by the Fruitvale, Hearns, Beaver Park and Glenmerry substations. The area has been reconfigured multiple times in recent years in an effort to defer the need for major capacity upgrade projects. After the projects proposed in the 2012 - 13 Capital Plan have been implemented (namely the Glenmerry Feeder 2 to Feeder 3 tie), the system can no longer be reconfigured to accommodate further load growth; at that time a station upgrade project will be required. In 2018 the Beaver Park, Fruitvale and Hearns Substation are forecast to exceed transformer nameplate rating. In that same year the Glenmerry T1 transformer will be operating at approximately 98 percent capacity.

This project entails expanding the existing Beaver Park Substation and installing a new 25 kV distribution transformer. The existing Beaver Park Feeder 2 running through the Beaver Valley will be converted to 25 kV and extended further east to interconnect into the Fruitvale and Hearns substations. At that time, the Fruitvale and Hearns substations could be offloaded entirely with the addition of strategically-located 25/13 kV step-down transformers. This would eliminate both stations and their associated condition and capacity issues.

Offloading the existing Beaver Park Feeder 2 from the existing Beaver Park T1 transformer will free up 13 kV capacity which could then be used to offload the Glenmerry T1 transformer. This would resolve the Glenmerry capacity deficiency out to the planning horizon.

This project optimizes both capital and operating expenditures by eliminating the ongoing operating costs for the aging Hearns and Fruitvale substations and also eliminates the need for capacity upgrade projects at multiple substations.

This project is estimated to cost $0.76 million in 2016, $10.46 million in 2017 and $10.31 million in 2018 with an in-service date of 2018.

Figure 2.8.8 (a) - Beaver Valley South Solution (before)

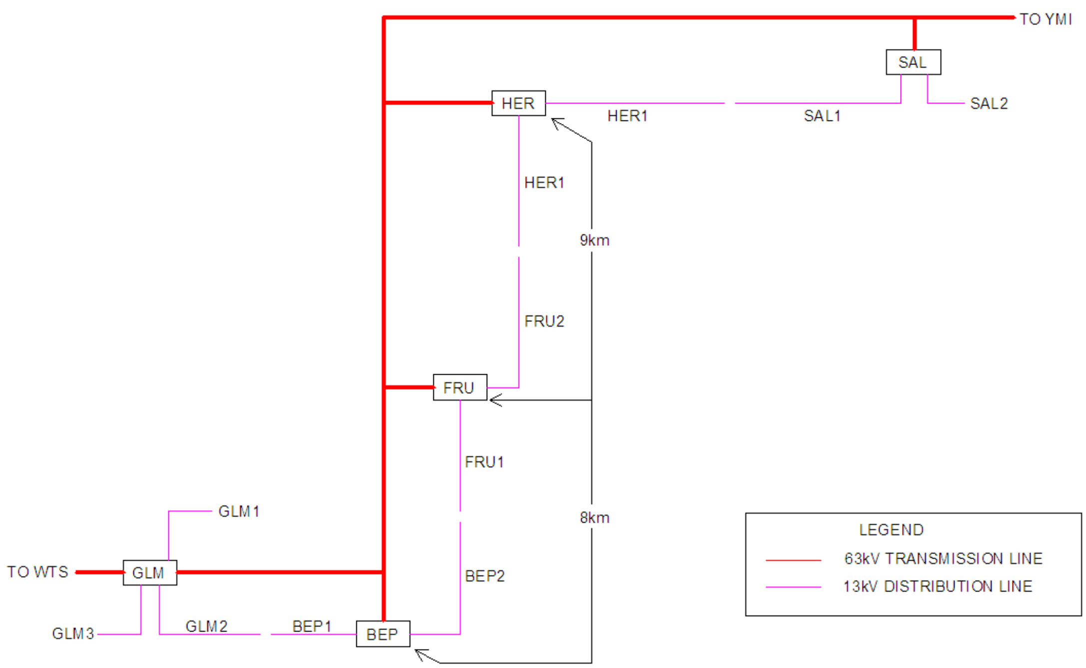
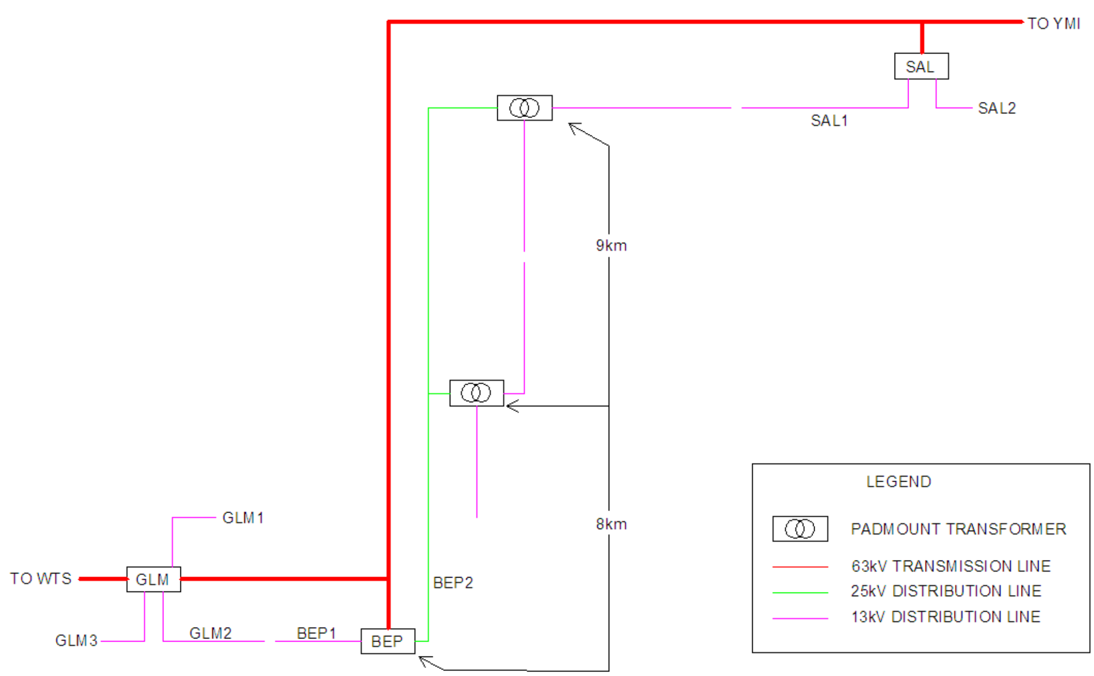


Figure 2.8.8 (b) - Beaver Valley South Solution (after)



2.8.9 RG ANDERSON DISTRIBUTION TRANSFORMER UPGRADE

The RG Anderson T3 transformer primarily is used to supply the City of Penticton municipal utility with a distribution wholesale supply. The transformer also supplies a small amount (less than 1 MW) of FortisBC customer load on a single feeder.

The load on the existing RG Anderson T3 transformer is forecast to exceed 95 percent of the contract Demand Limit in 2017. Under the terms of the wholesale supply agreement, FortisBC would be required to upgrade the supply capacity in order to continue to provide reliable service. It is proposed to replace the existing 20 MVA unit with the next larger FortisBC standard transformer which would be rated at 40 MVA. Forecasts indicate that this capacity would remain adequate out to the 20-year planning horizon.

This project is estimated to cost $3.03 million in 2016 and $4.06 million in 2017 with an in-service date of 2017.

2.8.10 DG BELL TERMINAL UPGRADES

The DG Bell Terminal upgrades consist of the following projects listed below.

Table 2.8.10 - DG Bell Terminal Upgrades

		2016	2017-31
		($000s)	
1	DG Bell Static VAR Compensator	3,031	34,285
2	DG Bell 230 kV Ring Bus	-	35,383
3	DG Bell Second 230/138 kV Transformer	-	18,746

2.8.10.1 DG Bell Terminal Static VAR Compensator

Currently, the load forecast for the Kelowna area indicates that voltage violations will occur in 2018 following single-contingency (N-1) outages during system peaks. The critical contingency is the loss of line 73 Line between the FA Lee Terminal in Kelowna and the RG Anderson Terminal in Penticton. The proposed solution is the installation of 150 Mvar Static VAR Compensator (SVC) at the DG Bell Terminal. Lower cost mechanically-switched capacitors were also considered, but system studies indicate that these devices cannot operate quickly enough to prevent a voltage violation from occurring. FortisBC already owns sufficient property at the site to accommodate the additional equipment; however, the substation fence-line boundary will need to be expanded.

It is important to note that the analysis which identifies the voltage violations during single contingency outages assumes that there is no local generation in the Kelowna area and that all load is supplied via the existing three 230 kV transmission lines. If considerable future resource additions were developed and were sited within the Kelowna area, then the need for the SVC could potentially be deferred.

2.8.10.2 DG Bell Ring Bus

Currently, the 230 kV 73 Line transmission line runs between the FA Lee Terminal in Kelowna and the RG Anderson Terminal in Penticton with a tap into the DG Bell Terminal in Kelowna. Presently there are no 230 kV automatic switching devices installed at the DG Bell Terminal tap location and thus a fault at any location on the line results in the separation of all three terminal stations. System load flow studies demonstrate that, based on the current load forecast, by the year 2030 an outage of 73 Line will cause a voltage collapse in the Kelowna area. In order to mitigate this, it is necessary to segment the existing line into two independent line sections: one portion will run directly from the FA Lee Terminal to the DG Bell Terminal and the other portion will run directly from the DG Bell Terminal to the RG Anderson Terminal.

To achieve this, the 230 kV portion of the DG Bell Terminal will be expanded and the required number of 230 kV circuit breakers to sectionalize the line will be installed. Providing the ring bus and sectionalizing the line will allow the removal of only the faulted section of line in the event of a forced outage. This allows the DG Bell 230/138 kV transformer to remain connected to a 230 kV supply source thus preventing the voltage collapse.

2.8.10.3 DG Bell Second 230/138 kV Transformer

Following the single contingency outage of the existing DG Bell Terminal 230/138 kV transformer, the flow on the three FA Lee Terminal 230/138 kV transformers will exceed their emergency ratings by 2030. To prevent this overload from occurring it will be necessary to increase the capacity of the DG Bell Terminal by adding a second 230/138 kV transformer. Along with the addition of the second transformer, there would also be the need to install the required number of 230 kV and 138 kV circuit breakers and associated protection and control equipment to support the connection of the new transformer.

Note that the analysis which identifies the overload during single contingency outages assumes that there is no local generation in the Kelowna area and that all load is supplied via the existing three 230 kV transmission lines. If considerable future resource additions were developed and were sited within the Kelowna area, then the need for the second DG Bell transformer could potentially be deferred.

2.8.11 VASEUX LAKE THIRD 500/230 KV TRANSFORMER

Based on the current load forecast, power flow studies indicate that following a single-contingency (N-1) outage of one of the Vaseux Lake Terminal station transformers, the power flow will exceed the emergency rating of the remaining transformer by 2025. A third 200 MVA 500/230 kV transformer and associated switching, protection and control equipment will be required to avoid this situation. The station was originally designed to accommodate the addition of this third transformer.

This project is reliability driven and is dependent on growth of the Okanagan area load. If this load was offset by the addition of appropriately-sited generation resources within the region, then the N-1 overload would be deferred or eliminated.

This project is estimated to cost $31.58 million with $1.78 million in 2023, $11.79 million in 2024 and $18.02 million in 2025 with an in-service date of 2026.

2.8.12 BOUNDARY AREA SUPPLY

In 2025, following a single contingency outage of one of the AS Mawdsley transformers, the power flow on the other transformer will exceed its summer emergency rating. In order to eliminate this problem the AS Mawdsley transformers will need to be replaced with larger capacity units. Consideration will be given for down-rating the operating voltage of 11 Line and 48 Line from 161 kV to 138 kV in conjunction with this project.

This project is estimated to cost $1.54 million in 2024 and $8.09 million in 2025 with an in-service date of 2026.

2.8.13 RECONDUCTOR 31 LINE (CRESTON AREA)

The substation load forecast currently predicts that the power flow on 31 Line supplying the Creston substation will exceed the ampacity rating of the line by 2030 during peak conditions. The 31 Line is a radial 63 kV transmission line fed from the AA Lambert terminal in Creston and supplies only the Creston distribution substation. The proposed solution is to reconductor 31 Line to a higher rated conductor. This is a growth-driven project and there will be structure replacements required due to the larger conductor and increased structure loadings. As a result, much of the line will need to be rebuilt; however, this project is not included in the Transmission Rebuild Plan (Appendix F) because the project is driven by the transmission capacity limitations of the line, and not by the condition of the line.

This project is estimated to cost $2.31 million with an in-service date of 2030.

2.8.14 STONEY CREEK TRANSFORMER ADDITION

The current load forecast indicates future transformation capacity limitations in the Trail area. Presently, the Stoney Creek substation supplies two 13 kV distribution feeders from the single Stoney Creek T1 transformer. The growing load in this area is forecast to exceed the capacity of the Stoney Creek T1 Transformer by the year 2024. A proposed solution is to add a second distribution transformer with new feeder positions in order to relieve the existing unit.

This project is estimated to cost $17.33 million with an in-service date of 2024.

2.8.15 PLAYMOR SUBSTATION DISTRIBUTION TRANSFORMER ADDITION

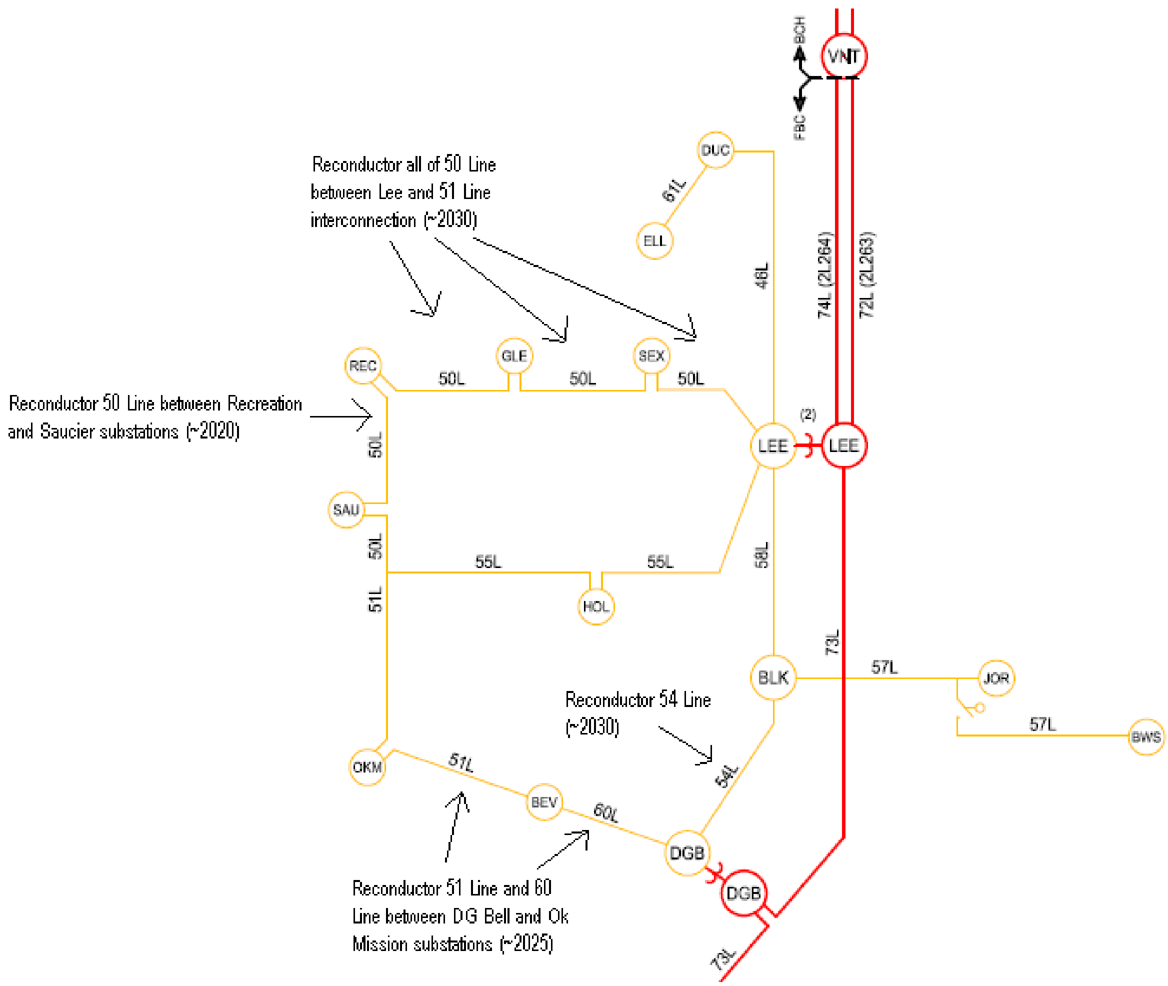
The current load forecast indicates future transformation capacity limitations in the South Slocan area. Presently, the Playmor substation supplies three 13 kV distribution feeders from the single Playmor T1 transformer. The growing load in this area is forecast to exceed the capacity of the Playmor T1 Transformer by the year 2027. A proposed solution is to add a second distribution transformer with new feeder positions in order to relieve the existing unit.

This project will begin in 2025 with an in-service date of 2027. The estimated costs are $1.70 million in 2025, $3.90 million in 2026 and $10.02 million in 2027.

2.8.16 RECONDUCTOR 50 LINE (EIGHT SPANS - RECREATION TO SAUCIER)

Eight spans of 50 Line from the Recreation substation to the Saucier substation are constructed with 477 kcmil ASC conductor while the rest of the line has a larger 927 kcmil ASC conductor. In 2025 following a single-contingency outage of 50 Line between the FA Lee Terminal and the Sexsmith substation, the flow on this section of line will exceed its summer emergency rating. Within the 20 year forecast period the entire line will need to be upgraded to a larger conductor to accommodate the forecast load growth; however, the project can be completed in two stages because of this eight span section of line with 477 kcmil ASC conductor, which currently limits the available capacity on the line. Completion of this project will remove the capacity limitation on this section of 50 Line, thus allowing the full capacity of the line to be utilized. Figure 2.8.16 below is a single-line diagram of the Kelowna area which shows how 50 Line supplies the various substations within Kelowna. The estimated cost of reconductoring the eight spans of 50 Line from Recreation to Saucier is estimated to cost $0.30 million in 2024.

Figure 2.8.16 - Single-line diagram of Kelowna area Transmission



2.8.17 RECONDUCTOR 50 LINE (REMAINING RECREATION TO SAUCIER)

The load forecast indicates that following a single-contingency outage of 50 Line between the FA Lee Terminal and the Sexsmith substation, the flow on the Recreation to Saucier section of line will exceed its summer emergency rating by the year 2035. The proposed solution is to reconductor this section of line to a larger conductor. The structures in this section of line are all concrete and steel and may be able to accommodate the larger conductor without requiring a large amount of structure replacements. A detailed review of the structure loadings will be conducted closer to when this project is required. The estimated cost of reconductoring 50 Line from Recreation to Saucier is estimated to cost $1.18 million in 2035.

2.8.18 RECONDUCTOR 50 LINE (REMAINING FA LEE TO SPRINGFIELD TAP)

The second stage of the 50 Line upgrade is to upgrade the remaining portion of the line to a larger conductor. In 2035, the forecast summer peak load for the connected substations is sufficient that during a single contingency event the power flow on sections of 50 Line will exceed the summer emergency rating of the current conductor size. Additionally, some upgrades to station equipment will be required to accommodate the increased line capacity. This is a growth-driven project and there will be a large number of structure replacements required due to the larger conductor and increased structure loadings. As a result, much of the line will need to be rebuilt; however, this project is not included in the Transmission Rebuild Plan (Appendix F). It is not considered a sustainment capital project as it is driven by the transmission capacity limitations of the line, and not by the condition of the line.

This project is estimated to cost $11.72 million with an in-service date of 2035.

2.8.19 RECONDUCTOR 51 LINE AND 60 LINE (DG BELL TO OK MISSION)

In 2030, the forecast summer peak will exceed the emergency capacity of 51 Line between the DG Bell Terminal and Benvoulin Substation, and 60 Line between the Benvoulin and OK Mission substations, during a single contingency outage of 50 Line between the FA Lee Terminal and the Sexsmith substation. The proposed solution is to reconductor both 51 and 60 Lines between the OK Mission Substation and the DG Bell Terminal to a higher-capacity conductor to provide adequate transmission capacity in the event of this contingency. Refer to Figure 2.8.16 above which shows how 51 and 60 Lines supply the substations in the south-Kelowna area. This is a growth-driven project and there will be a large number of structure replacements required due to the larger conductor and increased structure loadings. As a result, much of the line will need to be rebuilt; however, this project is not included in the Transmission Rebuild Plan (Appendix F). It is not considered a sustainment capital project as it is driven by the transmission capacity limitations of the line, and not by the condition of the line.

This project is estimated to cost $4.61 million in 2029 and $4.58 million in 2030 with an in-service date of 2031.

2.8.20 RECONDUCTOR 54 LINE (DG BELL TO BLACK MOUNTAIN)

The load forecast indicates that by 2035 during a single contingency of 60 Line between the DG Bell Terminal station and the Benvoulin Substation the power flow on 54 Line between the DG Bell Terminal station and Black Mountain Substation will be at its winter emergency rating. The proposed solution is to reconductor approximately 15 kilometres of 54 Line to a higher-capacity conductor to provide adequate transmission capacity in the event of this contingency. Figure 2.8.16 of the Kelowna area shows how 54 Line interconnects between the DG Bell Terminal station and the Black Mountain substation. This is a growth-driven project and there will be a large number of structure replacements required due to the larger conductor and increased structure loadings. As a result, much of the line will need to be rebuilt; however, this project is not included in the Transmission Rebuild Plan (Appendix F). It is not considered a sustainment capital project as it is driven by the transmission capacity limitations of the line, and not by the condition of the line.

This project is estimated to cost $2.02 million in 2034 and $8.48 million in 2035 with an in-service date of 2036.

2.8.21 KELOWNA AREA TRANSFORMATION CAPACITY ADDITIONS

Over the past ten years, Kelowna has been one of the fastest growing cities in the FortisBC service territory. This growth is expected to continue into the future as demonstrated by the substation load forecast provided in Appendix B. Localized substation transformer additions will be required in areas that are forecast to exceed capacity within the next 20 years. However, detailed distribution planning analysis can only be reasonably conducted within a five year planning horizon. As the following identified projects are outside this five year horizon there is some uncertainty as to the exact timing and location of the required additions. As well, each of the projects could potentially impact the timing of one another so it is possible that not all of the following transformer additions will be required within the 20 year timeframe.

The potential need for a future new distribution substation source in the North Kelowna area has also been identified. Currently, the timing for this project is shown at end of the 20 year planning horizon. However, as previously mentioned the transformer capacity projects in the Kelowna area are highly interrelated. Thus, depending on when and where new load growth occurs, the timing for this substation and the other transformer addition projects described below will be modified. Future planning studies will periodically review the development scenarios to identify specific capital projects and provide more certainty as to when they are required.

2.8.21.1 FA Lee Distribution Transformer Addition

Prior to the construction of the Black Mountain Substation, much of the load in the east Kelowna area was supplied by distribution feeders from the FA Lee Terminal and Hollywood substation. The need for the Black Mountain substation was justified by four primary needs:

1. Meeting distribution capacity requirements in the east Kelowna area;
2. Providing distribution backup support for other area substations and feeders;
3. Maintaining the reliability of the 138 kV transmission supply in the Kelowna area; and
4. Minimizing the risk to the FA Lee Terminal station transformers.

Item 4 refers to the fact that the FA Lee Terminal station distribution feeders were supplied by connections to the tertiary windings of the transmission transformers. In the CPCN application for the Black Mountain substation, it was demonstrated that this practice is unusual and undesirable; the higher frequency of distribution faults in the system increases the risk of damage to the transmission transformers. The Commission acknowledged this risk in the Decision accompanying Order C-7-07.

While the majority of the load supplied by the FA Lee Terminal station distribution feeders has now been transferred onto the Black Mountain Substation, a small portion of the load in the area is still supplied from the tertiary winding connection. Fully offloading of the FA Lee feeders was not possible due to fact that growth in the area occurred more quickly than expected, and due to other distribution feeder limitations. In the short term, the risk to transformers has been mitigated by the installation of fault-limiting reactors. Between now and the proposed project date of 2018, a number of smaller distribution upgrade projects are also proposed to allow for fully offloading the remaining FA Lee feeder.

Beyond 2018, the ability to supply area load from other substations is forecast to be exhausted and the need for a dedicated distribution source at the FA Lee Terminal station will be required. This project involves the addition of a distribution transformer and associated high and low voltage breakers at the FA Lee Terminal station. The installation of this transformer would also defer the need for a second Sexsmith transformer which is also forecast to reach full capacity around that time. Alternatively, the Sexsmith transformer addition is also a potential solution for the FA Lee distribution load and therefore would defer the FA Lee distribution transformer addition. For either solution, a more detailed study of the area will be required in the future as these transformers approach their capacity limits.

This project is estimated to cost $5.71 million in 2017 and $6.32 million in 2018 with an in-service date of 2019.

2.8.21.2 New Enterprise Substation

The existing Glenmore Substation is a major distribution supply for the central portion of Kelowna. The site provides six 13 kV feeders which supplies 7,000 FortisBC direct customers as well as one feeder which provides a wholesale supply to the City of Kelowna municipal electric system. The station is now fully populated with distribution feeder breakers and cannot accommodate new feeders without expansion and modification. As well, the City of Kelowna has conceptual plans for widening and adding to the adjacent roadways to support the future construction of the Central Okanagan bypass. If this work proceeds it would further limit the ability to expand and upgrade the existing substation.

FortisBC has received preliminary service requests from data center customers to supply new loads, in some cases greater than 20 MW. These customer sites would potentially be in the area served by the Glenmore Substation. The existing substation would be unable to accommodate any new spot loads greater than approximately 5 MW as these would likely require the addition of one or more distribution feeders.

The load forecast indicates that Glenmore Substation will have sufficient capacity to meet area loads until approximately 2020; at that time, a new supply point would be required. Currently, it is proposed to construct a new Enterprise Substation east of the existing Glenmore site at that time. If unexpected new load additions occur it may be necessary to advance this project. The new Enterprise Substation could either augment or replace the existing Glenmore Substation depending on the capacity requirements at the time.

Finally, if capacity increases occur at other substation sites (such as the addition of a second Sexsmith distribution transformer) that extra capacity could be used to offload some of the Glenmore Substation; this would potentially defer the need for the new Enterprise Substation. In the future, a more detailed study of the area will be required as these substations approach their capacity limits.

This project is estimated to cost $9.87 million in 2018, $12.61 million in 2019 and $13.32 million in 2020 with an in-service date of 2021.

2.8.21.3 Sexsmith Second Distribution Transformer Addition

The North Kelowna area is supplied by distribution feeders from the Duck Lake, Ellison, and Sexsmith Substations and the FA Lee Terminal. Presently the Sexsmith substation has four distribution feeders fed from the T1 transformer. The growing load in the area is forecast to overload the Sexsmith transformer by 2018. It is possible that the addition of a new distribution source at the FA Lee Terminal station, proposed for completion in 2018, could offload the Sexsmith station and thus defer the need for a second Sexsmith transformer, however the transformer addition at Sexsmith station with four new feeders is forecast at this time to be required. Depending on when and where load growth occurs in this area, this project may need to be advanced or deferred, and may also allow deferral of the FA Lee Distribution Transformer Addition project described in section 2.8.21.1.

This project is estimated to cost $3.07 million in 2019 and $6.31 million in 2020 with an in-service date of 2021.

2.8.21.4 Saucier Second Distribution Transformer Addition

The Saucier Substation is one of four major wholesale supply points to the City of Kelowna's municipal electric system. The load forecast indicates that the existing Saucier transformer will be at full capacity by 2022. The recent addition of a second transformer at the Recreation Substation in 2010 has increased the supply capacity for the City of Kelowna distribution system. Efforts will be made to supply as much new load as possible from the Recreation Substation in order to defer the Saucier upgrade project. Depending on when and where load growth occurs in this area, this project may need to be advanced or deferred.

This project is estimated to cost $3.57 million in 2021 and $3.85 million in 2022 with an in-service date of 2022.

2.8.21.5 Benvoulin Second Distribution Transformer Addition

The Benvoulin Substation was energized in December 2010 and supplies four distribution feeders from the T1 transformer. The need for an additional distribution transformer in the Benvoulin Substation will be driven by future load increases in the southeast Kelowna area. The current load forecast indicates an overload of the existing Benvoulin transformer in 2027. The proposed solution is to add a second transformer to increase the substation capacity and add four new feeders to offload the existing feeders. The need for this project is directly affected by a proposed project to add a second DG Bell Terminal distribution transformer. In the future, a more detailed study of the area will be required as these transformers approach their capacity limits. This future study will clarify the need and timing for each transformer addition; it is possible that the addition of a transformer at one site will defer or eliminate the need for the transformer addition at the other location.

This project is estimated to cost $3.79 million in 2026 and $7.97 million in 2027 with an in-service date of 2028.

2.8.21.6 Ellison Second Distribution Transformer Addition

The current load forecast indicates future transformation capacity limitations in the North Kelowna area. The Ellison Substation currently supplies four 13 kV distribution feeders from the single Ellison T1 transformer. The growing load in this area is forecast to exceed the capacity of the Ellison T1 transformer by the year 2027. The proposed solution is to add a second distribution transformer with four new feeder positions in order to relieve the existing unit. This project could be deferred if a new distribution source was added at the FA Lee Terminal or Sexsmith substation first.

This project is estimated to cost $2.84 million in 2026 and $5.01 million in 2027 with an in-service date of 2027.

2.8.21.7 DG Bell Second Distribution Transformer Addition

The current load forecast indicates an overload of the distribution transformer at the DG Bell Terminal station in 2027. The proposed solution is to install an second distribution transformer and additional distribution feeders to increase the substation supply capacity. As described in subsection 2.8.21.5 Benvoulin Second Distribution Transformer Addition project above, the need for this project is directly affected by the potential addition of a second Benvoulin Substation distribution transformer. In the future, a more detailed study of the area will be required as these transformers approach their capacity limits. This future study will clarify the need and timing for each transformer addition; it is possible that the addition of a transformer at one site will defer or eliminate the need for the transformer addition at the other location.

This project is estimated to cost $10.04 million in 2028 with an in-service date of 2028.

2.8.22 NEW CENTRAL OKANAGAN SUBSTATION

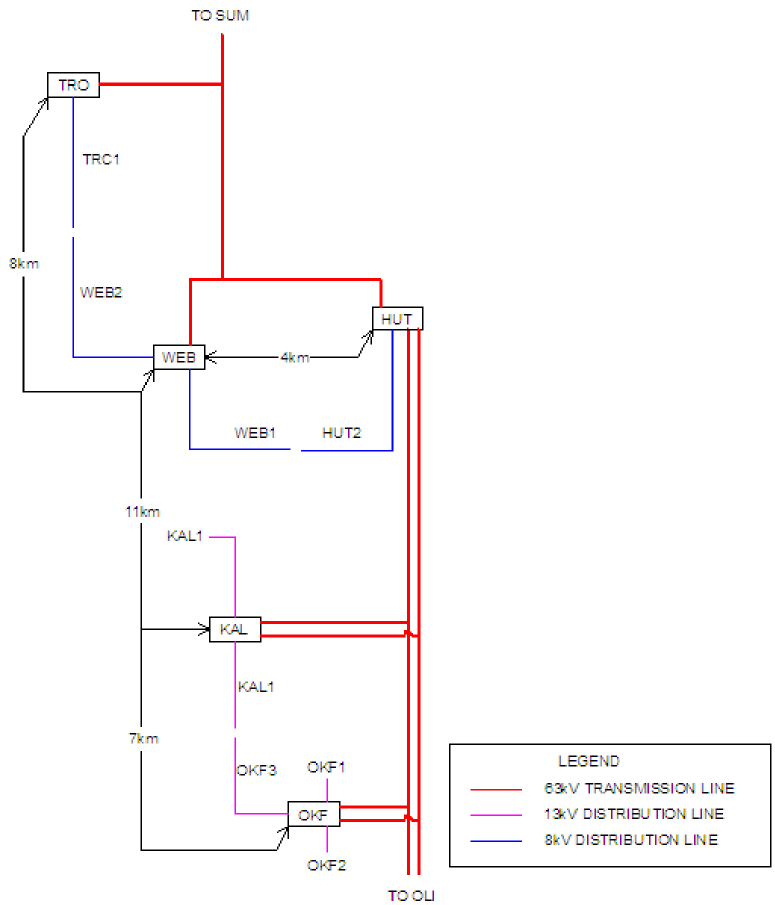
There are a number of capacity and condition-related issues associated with four smaller substations in the South Okanagan. These four stations are the Trout Creek, West Bench, Kaleden, and OK Falls Substations. Forecast currently show the West Bench substation transformer reaching its capacity limit in 2012; this overload can be mitigated for approximately five years by transferring excess load to the Trout Creek Substation. Forecasts also show the 60-year-old Kaleden transformer will be reaching its capacity limit by approximately 2018 during the winter peak. The Trout Creek Substation has a number of condition-related issues with the existing transformer and tapchanger. It is anticipated that replacement of some PCB-containing equipment such as transformer bushings and instrument transformers will be require at these stations due to their vintage. Finally, there is the potential for large load growth southwest of Penticton on Penticton Indian Band land.

The proposed solution which would resolve the issues described above is the construction of a new 25 kV station to the southwest of Penticton, currently referred to as the Central Okanagan Substation. This would provide a long-term capacity solution for the entire area and alleviate distribution capacity problems on some of the long radial distribution feeders by converting the distribution voltage to 25 kV.

The project would be implemented over several years and would begin with the new station being constructed in order to replace and salvage the existing Kaleden Substation which is expected to be the first station to reach its capacity limit. The new station would also be capable of supplying all new development on the Penticton Indian Band lands if and when that occurs. In the longer term, the extension of 25 kV feeders to supply the loads currently served by the existing West Bench and OK Falls Substations will be part of a longer-term development as required by load growth.

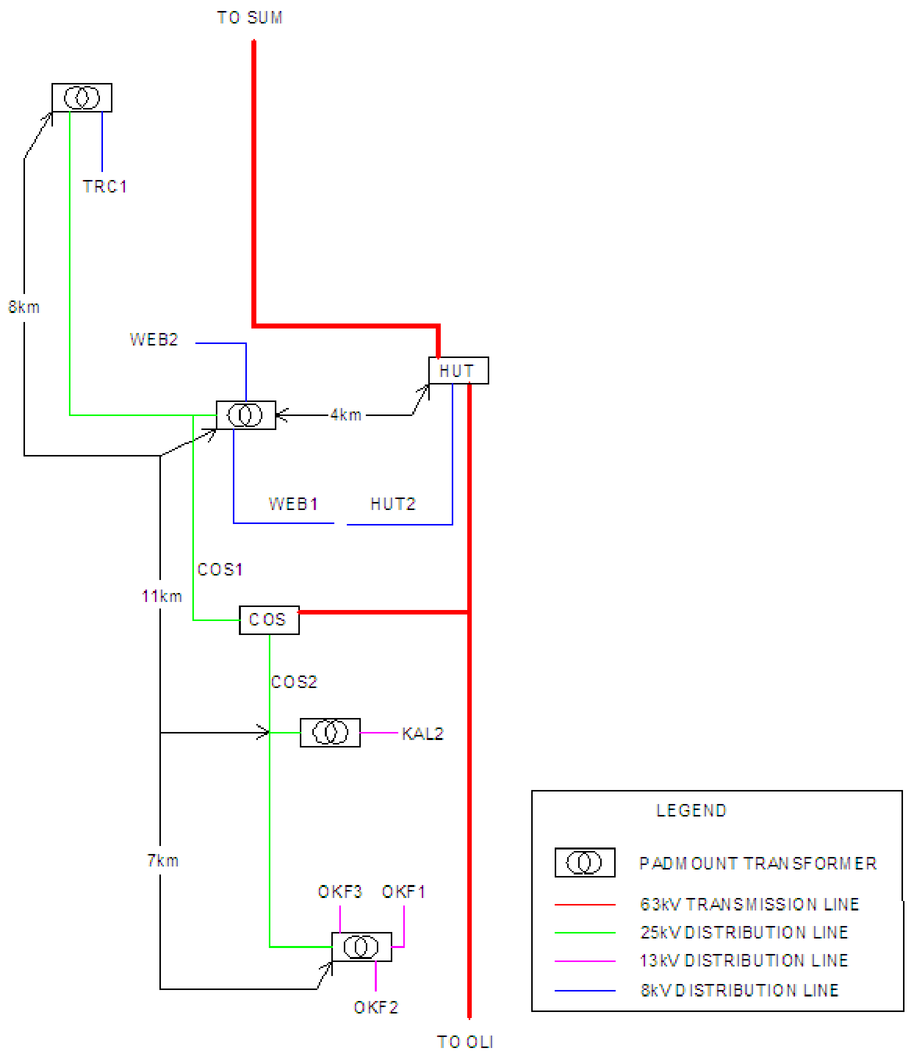
This project is estimated to cost $14.28 million in 2017, $15.06 million in 2018 and $7.66 million in 2019 with an in-service date of 2019.

1 **Figure 2.28.22 - New Central Okanagan Substation (before)**



2

Figure 2.8.22 - New Central Okanagan Substation (after)



2.8.23 CRESTON AREA CAPACITY INCREASE

Given current loading levels, neither of the two transformers at the Creston Substation is capable of providing backup to the full station load should the other transformer fail. The Creston Substation T1 transformer is forecast to exceed its capacity in 2024. Additionally, by that time both transformers will be approaching 56 years old. Due to the configuration of the substation and area distribution system there is limited ability to offload the substation to the adjacent AA Lambert Terminal distribution supply.

To take advantage of the unused capacity of the AA Lambert distribution source and to offload the Creston Substation transformers, this project entails expanding the AA Lambert distribution network by installing a new AA Lambert Feeder 4 breaker position. This new feeder breaker position (along with associated distribution system upgrades) will be used to create a looped distribution network between the AA Lambert Terminal and the Creston Substation.

This project is estimated to cost $7.11 million in 2023 and $6.91 million in 2024 with an in-service date of 2025.

2.8.24 RG ANDERSON - DG BELL SECOND 230 KV LINE

The load forecast predicts that a single contingency outage of the 230 kV Line (73 Line) between the RG Anderson and DG Bell terminal stations results in a voltage collapse in Kelowna outside the planning horizon. In order to prevent this voltage collapse from occurring, a second 230 kV circuit between the RG Anderson and DG Bell Terminals will be required.

Although this project is beyond this plan's timeframe, it is worth noting because it is reliability-driven and dependent on the Okanagan area load. If this load was offset by the addition of appropriately-sited generation resources within the region, then the N-1 overload would be deferred or eliminated.

This project is currently forecast to cost $80 million but has not been included in the summary table for Transmission and Stations projects.

2.9 Transmission Sustainment

Table 2.9 - Transmission Sustainment

	Transmission Sustainment	**2012**	**2013**	**2014**	**2015**	**2016**	**2017-31**
		($000s)					
1	Transmission Line Condition Assessment	522	485	480	547	543	10,216
2	Transmission Line Rehabilitation	3,372	2,621	2,509	2,424	2,820	50,158
3	Transmission Line Urgent Repairs	594	620	616	622	661	11,543
4	Transmission Line Right of Way Easements	400	400	416	423	440	7,754
5	6 Line/26 Line River Crossing Reconfiguration	1,185	-	-	-	-	-
6	27 Line Rebuild (Corra Linn-Salmo)	1,161	-	-	-	-	-
7	21-24 Lines Rebuild (Generation Plants)	2,219	-	-	-	-	-
8	19 Line/29 Line Reconfiguration	-	791	-	-	-	-
9	20 Line Rebuild (Warfield Terminal-Salmo)	-	4,664	-	-	-	-
10	30 Line Lake Crossing Assessment and Rehabilitation	-	-	-	802	1,521	-
11	**Total Transmission Sustainment**	**9,453**	**9,581**	**4,021**	**4,818**	**5,984**	**79,671**

FortisBC's Transmission Sustainment capital programs are:

- Transmission Line Condition Assessment;
- Transmission Line Rehabilitation;
- Transmission Line Urgent Repair;
- Transmission Line Right of Way Easements; and
- Transmission Line Rebuild

These projects are described in the following sections.

2.9.1 TRANSMISSION LINE CONDITION ASSESSMENT

The Transmission Line Condition assessment program is based on an eight-year cycle of patrolling and testing all of FortisBC's transmission line facilities. The program consists of a pole "test and treat" and a condition assessment. The test and treat component involves drilling test holes in each pole to confirm the condition of the pole, and the addition of a chemical treatment to reduce internal rot in the pole.

The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The test and treat program deals with the portion of pole at and 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 based on rolling average estimates combined with the Company's knowledge of the distribution lines expected to be assessed. 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.sam

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

2.9.3 TRANSMISSION LINE URGENT REPAIR

The Urgent Repairs project is required to replace transmission line facilities that fail in-service due to severe weather, vandalism or other unexpected reasons. The project is required to address public and employee safety issues, environmental concerns and to maintain reliable service to FortisBC customers.

Table 2.9.3 - Transmission Line Urgent Repair

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	514	362	526	487	491	594	620	616	622	661	11,543

2.9.4 TRANSMISSION LINE RIGHT OF WAY EASEMENTS

This program is required to acquire outstanding rights of way or non-easement land rights for transmission and distribution lines that are in trespass. Many of the transmission lines have no or limited access to sections of the right of way. Access is required for the operation and maintenance of these lines. This program has historically been used to obtain easements to address existing trespass situations. Easements for new projects are obtained as part of the new project and are not included in this program.

Table 2.9.4 - Transmission Line Right of Way Easements

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	170	135	235	118	358	400	400	416	423	440	7,754

2.9.5 TRANSMISSION LINE REBUILD

The Ten Year Transmission Rebuild Plan found in Appendix F, includes transmission rebuilds that are focused on the replacement of:

- Previously inspected “red tagged” structures and cross-arms;
- Stubbed poles that have deteriorated enough at the pole tops and cross-arms to justify complete replacement; and
- Correction of circuit spacing issues, and improved anchoring where needed.

The plan identifies seven 63 kV transmission lines located in the Kootenay region requiring significant rehabilitation/rebuild. As well, there are two transmission reconfiguration projects required in the Kootenay region. These line rebuild and reconfiguration projects have been assessed consistent with the criteria of the Transmission Rehabilitation program and require a large amount of pole replacements and upgrading.

The included transmission rebuilds do not generally include rerouting or growth-driven reconductoring projects with the exception of two small reconfiguration projects. All other projects identified in this plan are generally a "like-for-like" structure replacement as well as repair work similar in scope to the FortisBC Transmission Rehabilitation program but larger in magnitude.

In its Reasons for Decision accompanying FortisBC's 2009 - 2010 Capital Expenditure Plan, the Commission directed the Company to submit a ten-year plan for its Transmission Line Rebuild projects. The Ten Year Transmission Plan is attached as Appendix F. A summary of the projects discussed in the Ten Year Transmission is provided below.

20 Line Rebuild

This project is required to maintain-service reliability and alleviate safety concerns for the customers in the Trail, Waneta, Montrose, Fruitvale and Salmo areas. 20 Line is a 63 kV circuit that was constructed in 1931. It is approximately 46 kilometres in length, and runs from Warfield Terminal station to Salmo with distribution substations at Glenmerry, Beaver Park, Fruitvale, and Hearns in between. The line includes portions of three phase distribution underbuild between Beaver Park and Salmo. The Beaver Park to Salmo section is also primarily along road and highway rights of way and is in close proximity to the tree line. Historically, only urgent repairs have been addressed.

In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The study identified many structures that are either "red tagged" for replacement or stubbed beyond the recommended life extension period. Also identified was significant pole top and crossarm rot, further verifying end of life. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, sub-standard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have all been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report that was created considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centres, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs, using up to date pricing. The report concluded that 52 structures require repairs and 152 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement. Notice the majority of poles are older than 50 years. The current cost estimate and schedule for the project is shown below.

Table 2.9.5 (a) - 20 Line Expenditure Plan

Year	**2013**
Cost ($millions)	4.66

27 Line Rebuild

This project is required to maintain-service reliability and alleviate safety concerns for the customers in the Nelson, Whitewater, Ymir and Salmo areas. 27 Line is a 63 kV circuit that was constructed in 1930. It is approximately 57 kilometres in length and runs from Corra Linn to Salmo with Rosemont Switching Station, Cottonwood, and Ymir substations in between. 27 Line has a variety of configurations consisting primarily of three-phase and single-phase distribution underbuild, as well as some single circuit transmission with no underbuild. The line has many sections with significant setback from the highway and is generally on its own separate right-of-way. There have been some structure changes to the line over the years; but there are still many structures that are either “red tagged” for replacement or stubbed beyond the recommended life extension period including structures with significant pole top and crossarm rot.

In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, substandard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centers, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs and as a priority under the 2009 rehabilitation budget, using up to date pricing. The report concluded that 84 structures require repairs and 14 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement.

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

Table 2.9.5 (b) - 27 Line Expenditure Plan

Year	**2012**
Cost ($millions)	1.16

21-24 Line Rebuild

21 - 24 Lines interconnect all four FortisBC owned river plants on the Kootenay River. Line 21 is 2.1 kilometres long and spans from the South Slocan plant to the Lower Bonnington plant. Line 22 is 3.6 kilometres long and spans from the South Slocan plant to the Upper Bonnington plant. Line 23 is 5 kilometres long and interconnects all four river plants spanning from South Slocan plant to the Corra Linn plant. Line 24 is also 5 kilometres long and spans from the South Slocan plant to the Corra Linn plant. These lines are all of the 60+ year vintage and in very poor condition. Similar to both 20 Line and 27 Line a detailed engineering assessment was done in 2008 to identify the deficiencies and risks and explore some options for rebuild. The outcome of the study was to do a like for like replacement of the structures over about a 10-15 year period of time but to replace all urgent structures in the next capital plan. Like the 20 Line and 27 Line assessment reports, the 21-24 Line report was also updated for submission in the 2012-13 Capital Expenditure Plan with up to date scopes and estimates. During the next couple of condition assessment/rehabilitation cycles the remaining substandard condition structures would be replaced to reduce the effects of the large capital expenditure in one capital plan. Outages on these lines can potentially have large financial implications if the outages result in a generator forced outage. Scope for this project is very similar to the 20 and 27 Line rebuilds with mainly structure replacement. Line 21 requires 10 structure replacements, Line 22 requires 23 structure replacements, Line 23 requires 29 structure replacements and Line 24 requires 37 structure replacements for a total of 99 structure replacements.

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

Table 2.9.5 (c) - 21-24 Line Expenditure Plan

Year	**2012**
Cost ($millions)	2.22

6 Line / 26 Line River Crossing Reconfiguration

Both 6 Line and 26 Line originate at the Brilliant Switching station and split off into four transmission lines that cross the Kootenay River at two locations, one on the upstream (eastern) and one on the downstream (western) side of the Brilliant Bridge on Highway 3A. This creates two dual source supply lines for the Castlegar area current configuration. One loop supplies the Castlegar substation, Interfor Forest Products and ties in with Zellstoff Celgar while the other loop supplies the Ootischenia and Blueberry distribution substations.

This project involves work on the transmission lines on the upstream and the transmission and distribution lines on the downstream side of the bridge crossing the Kootenay River at the north east end of Castlegar.

In 2009, FortisBC experienced a pole top failure on one of the distribution river crossing structures, resulting in a live conductor falling into the Kootenay River. The Company/external consultant performed an engineering analysis on the remaining river crossing structures and all structures except one, which was replaced six years ago (6L19), showed various signs of requiring rehabilitation or replacement. Four structures were recommended to be replaced in a non urgent manner in the next capital expenditure plan, one structure was considered to be marginal and could possibly last for another eight year cycle and two structures do not have a sufficient pole diameter for current standards.

Various options were explored to determine how to best rehabilitate the crossings, including a like for like rehabilitation of all four river crossings. It was determined that it would be more efficient from an operational and environmental perspective to salvage the upstream transmission river crossings and to create a new tap point between the loops of 6 Line and 26 Line rather than to rehabilitate all four river crossings like for like.

The reconfiguration will reduce the ongoing capital rehabilitation expenditures required to maintain the lines through the condition assessment program. It will also reduce public safety and environmental risk exposure from river crossing failures by eliminating two long redundant spans of conductor across the Kootenay River which is heavily populated with a wide variety of fish including Sturgeon.

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

Table 2.9.5 (d) - 6 Line/26 Line River Crossing Reconfiguration

Year	2012
Cost ($millions)	1.19

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	2012
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	**2012**	**2013**
Cost ($millions)	0.80	1.52

2.10 Stations Sustainment

FortisBC owns 64 substations, with over 2,000 pieces of major equipment such as power transformers, circuit breakers and disconnect switches. As well, there are numerous ancillary systems such as protection and control equipment, station batteries, station service supplies and grounding systems. These assets are managed to provide safe and reliable operation at the lowest reasonable cost to customers, and the projects outlined below are necessary to achieve these objectives. Reinvestment in the asset base over the duration of this plan is required to address assets near the end of their service life. Many of these assets were added to the system to meet growth during the 1960s and 1970s and in some cases are reaching the end of their service life. The proposed station projects and costs are provided in the table below.

Table 2.10 - Station Sustainment

	Stations	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Environmental Compliance (PCB Mitigation)	11,269	11,553	4,574	-	-	-
2	Station Urgent Repairs	818	907	879	977	942	17,065
3	Station Assessment/Minor Planned Projects	1,343	1,354	1,410	1,433	1,489	26,245
4	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	566	1,140	1,184	-
5	Huth Low Voltage Breaker Replacement (2)	-	69	550	-	-	-
6	Switchgear Replacement Program (13 kV)	-	-	1,651	-	983	2,651
7	Ground Grid Upgrades	-	-	748	-	790	6,403
8	DG Bell 138 kV Breaker and Voltage Transformer Addition	-	-	338	938	-	-
9	Osoyoos 63 kV Breaker Additions (2)	-	-	-	364	2,359	-
10	Bulk Oil Breaker Replacements	-	-	-	733	761	2,972
11	Station Oil Containment	-	-	-	445	462	2,664
12	Minimum Oil Circuit Breaker Replacement	-	-	-	-	-	21,175
13	Major Transmission Transformer Replacements	-	-	-	-	-	32,017
14	Distribution Transformer Replacements	-	-	-	-	-	10,978
15	**Station Sustainment Total**	**13,969**	**14,427**	**10,716**	**6,030**	**8,970**	**122,170**

2.10.1 ENVIRONMENTAL COMPLIANCE (PCB MITIGATION)

The *Canadian Environmental Protection Act PCB Regulations (SOR/2008-273)* came into effect on September 5, 2008. The purpose of the *PCB Regulations* is to improve the protection of Canada's environment and the health of Canadians by minimizing the risks posed by the use, storage and release of polychlorinated biphenyls (PCBs) and by accelerating the elimination of these substances.

Before the publication of the *PCB Regulations* in 2008, substation equipment was considered contained and thus at a low risk for PCB release. The equipment was not a subject of concern based on previous testing and previous decontamination of the high oil volume equipment. However, the *PCB Regulations* require all substation equipment, including small volume units such as bushings and instrument transformers, to be addressed by 2014. By the end of 2014, FortisBC will be compliant with the *PCB Regulations* for station equipment. 2011 expenditures for PCB mitigation approved by BCUC Order G-195-10 are being used to mitigate contaminated equipment and plan for the work required to be compliant with the *PCB Regulations*. During the period from 2012 to the end of 2014, work will be carried out to remove any PCB contaminated equipment containing higher than 500 mg/kg from FortisBC substation sites. Expenditures of approximately $25.6 million will be required to meet the station equipment compliance requirement by December 31, 2014.

A future application will be made the British Columbia Utilities Commission to meet the 2025 compliance date for all remaining PCB contaminated equipment to less than 50 mg/kg. This is equipment which is located both within substation properties and along the distribution network and for which Environment Canada has permitted an operating extension until 2025. Planning and testing for the future removal and destruction of PCB-containing overhead distribution equipment will start in 2015, based on best management practice and experience gained in the previous PCB program.

This project is estimated to cost $ 27.40 million with $11.27 million in 2012, $11.55 million in 2013 and $4.57 million in 2014. Some of these costs may be deferred if the PCB contaminated equipment is found to have concentration between 50 and 500 mg/kg. This equipment will then be replaced during regular maintenance cycles in the period 2015 - 2025.

2.10.2 STATION URGENT REPAIRS

The Station Urgent Repair program is required to address unexpected failures of in-service equipment. Component failures in substation systems occur due to inclement weather, defective equipment, animal intrusions, vandalism, and abnormal operating conditions. These failures can cause outages or present safety or equipment risks that must be addressed in an expedient manner. The Station Urgent Repairs program is required to address public and employee safety, environmental concerns and to maintain reliable service to FortisBC customers.

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	818	907	879	977	942	17,065

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.

Table 2.10.3 - Station Assessment and Minor Planned Projects

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	2,148	1,509	286	286	708	1,343	1,354	1,410	1,433	1,489	26,245

2.10.4 SPECIFIC STATION PROJECTS

The specific station projects planned are identified in the table below.

Table 2.10.4 - Specific Station Projects

	Project Name	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	566	1,140	1,184	-
2	Huth Low Voltage Breaker Replacement (2)	-	69	550	-	-	-
3	Switchgear Replacement Program (13 kV)	-	-	1,651	-	983	2,651
4	Ground Grid Upgrades	-	-	748	-	790	6,403
5	DG Bell 138 kV Breaker and Voltage Transformer Addition	-	-	338	938	-	-
6	Osoyoos 63 kV Breaker Additions (2)	-	-	-	364	2,359	-
7	Bulk Oil Breaker Replacements	-	-	-	733	761	2,972

2.10.4.1 Add Arc Flash Detection to Legacy Metal-Clad Switchgear

FortisBC has a large number of distribution substations equipped with older, non arc-resistant metal-clad switchgear. 2011 expenditures for this program were approved by Order G-195-10. This type of switchgear presents a risk of injury if a fault occurs within the switchgear when employees are inside or nearby. Arc flashes occur when a short circuit flows through air. Arc flash incidents release substantial amounts of energy in a very short period of time, resulting in explosive, high temperature events with severe consequences to employees and equipment.

The long-term goal is to retire this type of equipment, but in the interim some measures must be taken to reduce the risk of injury where practical. The program would install arc flash detector relays in legacy metal-clad installations. These devices reduce the fault detection time, and thus exposure duration, associated with a metal-clad insulation failure. These relays would trip either the transformer high-side breaker or low-side main breaker, as applicable. The installation of these relays allows for safer working conditions for employees working near legacy metal-clad switchgear until the legacy switch-gear can be replaced.

Legacy stations that are planned for future replacement benefit from the installation of arc flash relays through the increased safety provided. Some stations to be retrofitted with arc flash detection relays are also scheduled for future switchgear replacement in the condition-based Switchgear Replacement Program (section 2.10.4.3). If the switchgear replacement occurs, the arc flash detection relays will be reused at other locations. The substations in the Okanagan have relatively newer switchgear and replacement of this equipment due to condition issues is not likely to occur for many years. In the interim, the addition of arc flash relays to this legacy non-arc flash resistant switchgear will greatly improve the safety of operations while costing substantially less than a complete switchgear replacement. For example, the Hollywood substation has 12 cells and the cost of the arc flash retrofit is estimated at $176,000 in 2013. This is substantially less than the cost of complete replacement or refitting the switchgear with arc-resistant doors.

2.10.4.2 Huth Low Voltage Breaker Replacement (2 units)

The bulk oil circuit breaker protecting the 8 kV bus at the Huth substation failed during maintenance testing, reducing reliability and decreasing operational flexibility to 8 kV supply for the City of Penticton.

The Feeder 1 breaker was manufactured in 1943 and has reached its end of life. Replacement parts are unavailable for this unit. The loss of this breaker requires the high voltage breaker to trip during fault conditions on the low voltage bus, de-energizing the 8 kV supply at the station. Frequent re-energizing of the transformers following distribution faults using the high-side breaker puts undesirable strain on the transformers.

The Feeder 2 breaker was manufactured in 1938 and is operable, but is subject to the same parts constraint as the Feeder 1 breaker. Replacing these units will also reduce the risk of oil contamination, as oil containment pits are not installed for either breaker. The replacement units will improve the reliability and operability of the 8 kV system. Both breakers will be replaced with FortisBC-standard 13 kV equipment.

This project is estimated to cost $0.62 million with a projected start date of 2013 and a necessary in-service date of 2014.

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 2029 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.

2.10.4.4 Ground Grid Upgrades

This program seeks to improve station ground grids at locations where the existing grid has a decreased ability to provide a solid ground reference. Ground grid effectiveness can be decreased due to deterioration of their above and below-ground connections, corrosion to the grounding conductors, increases in fault levels since the original design of the ground grid, repeated high-magnitude fault currents which can weaken connections, and adverse soil conditions. Ground grids are inspected during the Station Condition Assessments inspections on a ten year cycle. Historically, condition assessment of the ground grids has indicated poor grounding at some stations.

Where above ground connections show corrosion or damage, second stage testing is conducted to establish the sufficiency of the below ground connections. Anomalies found in this process are subjected to a full ground grid study, and projects arising out of the ground grid study are the focus of this program. The 2010 assessments identified one station for second stage testing to take place in 2011.

The next phase of the Ground Grid Upgrade program will begin remediation work in 2014 with the aim of correcting deficiencies every second year. This will allow sufficient time to undertake testing and identify grids which need remediation.

Reliable, solidly grounded substation grids are necessary for employee safety in substations, for public safety near the stations, and for proper operation of protection relays to ensure safe and rapid clearing of system faults.

This project is estimated to cost $7.94 million with costs incurred every two years beginning in 2014 as shown below.

Table 2.10.4.4 - Ground Grid Upgrades

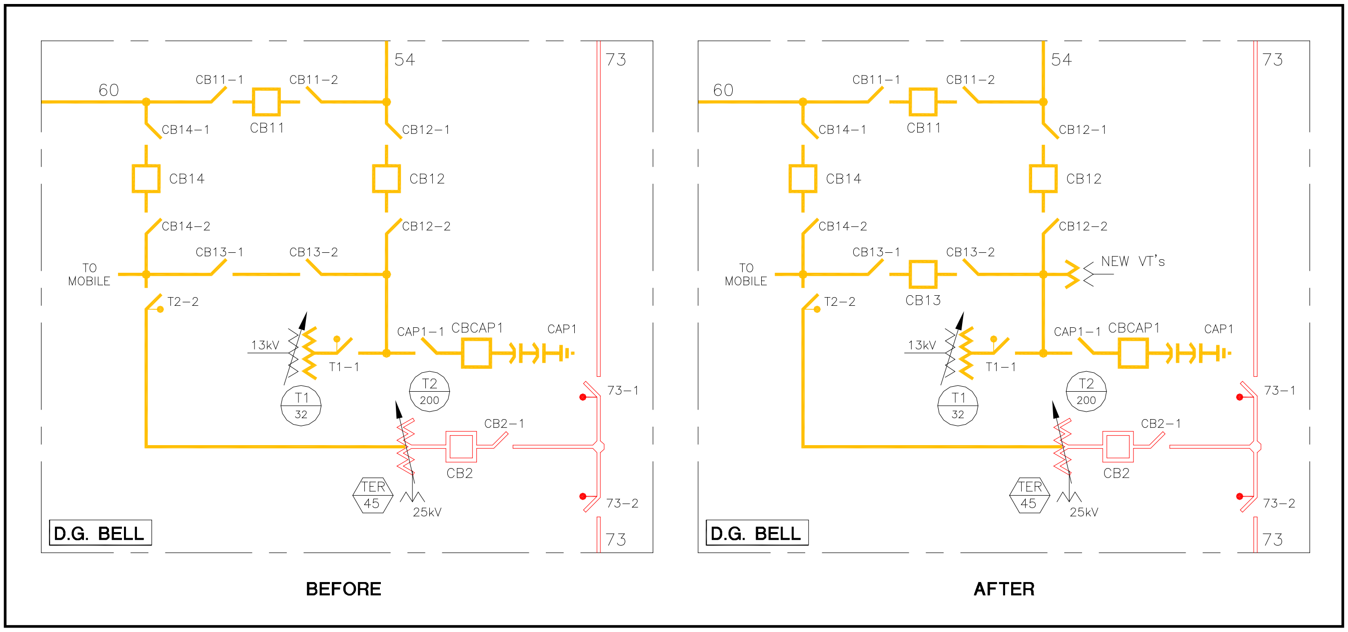
Year	2014	2016	2018	2020	2022	2024	2026	2028	2030	Total
	($000s)									
Cost	748	790	741	799	937	872	984	1,043	1,028	7,941

2.10.4.5 DG Bell 138 kV Breaker Addition

The DG Bell Terminal station has been designed and provisioned to have a four-element ring bus in the 138 kV portion of the station. At this time, only three circuit breakers are installed. The addition of the fourth circuit breaker will improve reliability, operational flexibility and simplify the substation protection schemes. The recent installation of a capacitor bank to the existing node between Circuit Breaker 14 (CB14) and Circuit Breaker

12 (CB12) has increased the number of devices connected to this bus section. Currently, the DG Bell T1 and T2 transformers, the mobile transformer connection and the capacitor bank are all included in the same protection zone. A fault with one piece of equipment will cause all units in this zone to experience an outage. Refer to the "Before" section of Figure 2.10.4.5 below for this configuration.

Figure 2.10.4.5 - DG Bell Terminal "Before and After" Configuration



The addition of CB13 will increase reliability and simplify the protection schemes at the substation by increasing the sectionalization of equipment at the station, as well as providing trip coordination with upstream and downstream protection equipment. The station was designed for the CB13 addition; the required isolating disconnect switches are already installed. At present, the 138 kV node encompasses the low voltage side of the terminal transformer T2 (230 kV-138 kV), the distribution transformer T1, and capacitor bank and the mobile transformer connection. Any faults in this node jeopardize all these pieces of equipment.

Along with the addition of CB13, voltage transformers will be added to the high voltage side of transformer T1 between circuit breakers 12 and 13 (CB12 and CB13) in accordance with FortisBC design standards.

The Bulk Oil Breaker Replacement program will impact this project as both CB12 and CB14 are bulk oil breakers and are thus scheduled for replacement.

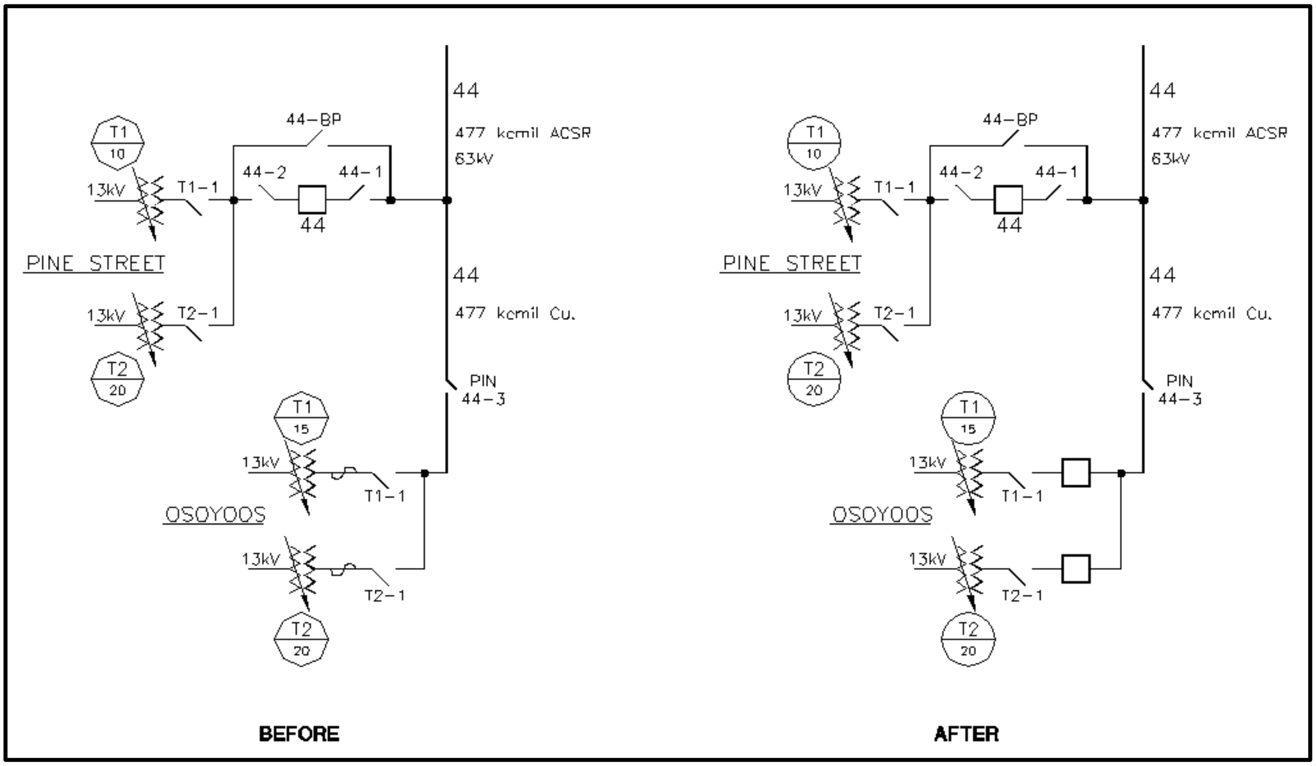
This project is estimated to cost $1.28 million with a projected start date of 2014 and completion in 2015.

2.10.4.6 Osoyoos Substation 63 kV Breaker Additions (2)

The T1 and T2 transformers at the Osoyoos Substation are 15 MVA and 20 MVA respectively and have fuses protecting the transformers on the high voltage side. The FortisBC standard for the high voltage protection of transformers 10 MVA and above is to provide transformer protection using circuit breakers or circuit switchers. Installing circuit breakers for the Osoyoos transformers T1 and T2 will bring them up to current standards.

The existing fuses coordinate poorly with upstream transmission line protection, provide no power transformer overload protection and provide poor backup for downstream devices. In addition, fuses have longer clearing times for low voltage bus faults, increasing the fault duration. Fuses can also cause single-phasing and customer equipment damage when only one high voltage fuse link operates. Circuit breakers will provide better protection to the transformers as well as providing increased protection to the low voltage bus and breakers, improved isolation, quicker restoration time in the event of trips, increased reliability and improved employee safety. This increases the likelihood that any possible resulting transformer damage will be minimized, and therefore repairs to transformer possible. Planning and engineering will cost approximately $0.36 million in 2015, with construction to be completed in 2016 at an estimated cost of $2.36 million.

Figure 2.10.4.6 - Fuses

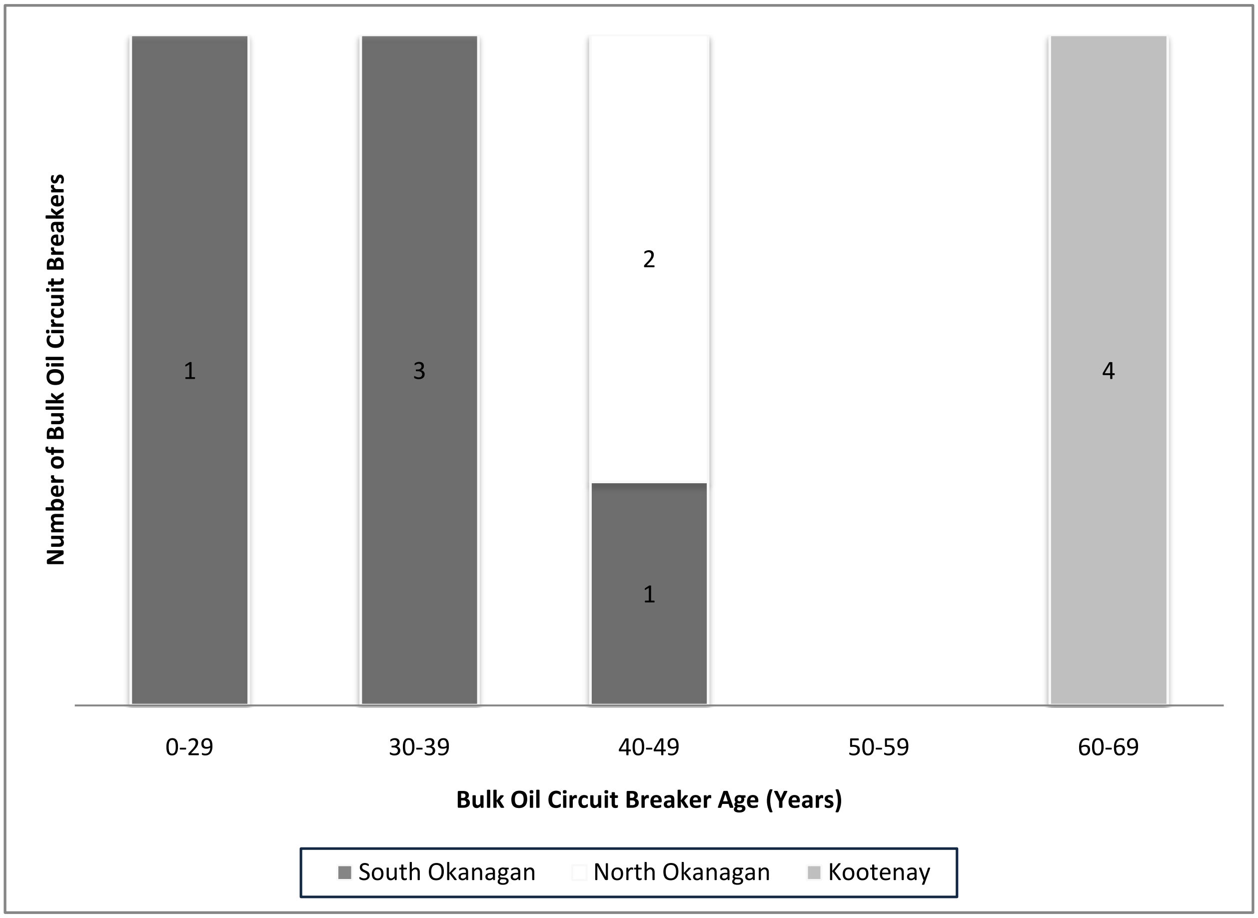


2.10.4.7 Bulk Oil Breaker Replacement Program

FortisBC has a total of 11 transmission bulk oil circuit breakers of 1947 to 1982 vintage. These units can contain several thousand litres of insulating oil, however none of these high voltage bulk oil circuit breakers have oil containment pits to prevent ground contamination in the event of oil release from the breaker. Replacement parts are also no longer available for many of these breakers.

This program (which was originally included in the FortisBC 2005 System Development Plan and approved by Commission Order G-52-05) proposes to continue replacing the legacy bulk oil breakers with modern SF6 circuit breakers. The new units are more reliable and require less maintenance than bulk oil breakers. Replacing the breakers also removes the need to install oil containment pits and prevents the associated complication of stranding the oil containment pits when the breakers are removed from service at a later date.

Figure 2.10.4.7 - High Voltage Bulk Oil Circuit Breaker by Region



This program proposes the replacement of two breakers per year over the period of 2015 to 2020. The breakers will be replaced based on the asset condition assessment consistent with FortisBC's proposed Asset Management program, currently being developed. This project is estimated to cost $4.47 million dollars over the 2015 - 2017 timeframe.

2.10.4.8 Station Oil Containment

Legacy substations often do not have oil containment pits to prevent oil release into the environment. Many of the historical substation sites are in locations which would now be considered environmentally sensitive. To reduce the risk of transformer oil contaminating soil, groundwater and nearby waterways, this program will retrofit oil containment pits for legacy substations, either adding containment pits where they do not currently exist or upgrading containment pits that are considered inadequate. The work will be performed to mitigate stations that pose the highest risk to the surrounding environment.

The Institute of Electrical and Electronic Engineers (IEEE) published a 1992 study of 59 utility respondents in North America and found the following practices:

- 57 percent install containment when oil volume exceeds 2,500 litres; and
- 86 percent provide secondary containment for power transformers.

Bulk oil circuit breakers can contain up to 10,000 litres of oil. Power transformers range from 15,000 to 30,000 litres for distribution substation power transformers to over 70,000 litres for terminal transformers. This project will run for six years starting in 2015 and will retrofit or upgrade oil containment pits for large volume pieces of substation equipment such as power transformers and distribution bulk oil circuit breakers. These pieces of equipment will be selected by studying and ranking them according to the risk posed to waterways, ground water supplies, environmental impact, and in accordance with the FortisBC Asset Management plan, currently under development.

This project is estimated to cost $0.45 million in 2015, $0.46 million in 2016 and a further $2.66 million in 2017-2020.

2.10.4.9 Minimum Oil Circuit Breaker Replacement

FortisBC's fleet of Minimum Oil Circuit Breakers (MOCBs) is aging and will require replacement to maintain acceptable standards of reliability. The median age of the MOCB asset class was 25 years in 2010 and will rise to 45 years by 2030. As this asset class ages, maintenance expertise and spare parts will become increasingly scarce.

When minimum oil circuit breakers operate severe stress is put on the operating mechanism. Within FortisBC's system, these circuit breakers do not necessarily operate frequently, therefore the breakers can continue to provide protection into the future. However, of concern are the availability of spare parts and the breakdown of insulation systems in the breakers. In 2010, a circuit breaker of this type failed violently at the AA Lambert Terminal station; an insulation failure of the operating rod within the MOCB was determined the likely cause.

These breakers will continue to be monitored and assessed, and replacement will be carried out in accordance with the FortisBC Asset Management plan, currently being developed. The Minimum Oil Circuit Breaker Replacement program will replace MOCBs at a rate of two per year starting in 2017 and continuing until 2035. At this rate, 36 of 46 breakers will be replaced by the program end. The remaining breakers will range from 42 - 46 years old.

Replacements will be made based on a condition assessment of the equipment. As these units are taken out of service, the inventory of spare parts salvaged can be used to extend the life of remaining units as necessary.

The Kootenay region has 10 MOCBs with an average age of 26 years. The Okanagan has the majority of the units. The Kelowna area contains 18 units with an average and median age of 27 years. The South Okanagan has 16 breakers with a slightly younger population of breakers at a median age of 22.

This project is estimated to cost $21.18 million over the 2017-31 timeframe.

2.10.5 TRANSFORMER REPLACEMENTS

FortisBC has over 100 transformers of various sizes in-service. The average life span of a transformer is 40 to 50 years, with a standard deviation of 20 years, which gives a replacement range of 30 to 70 years[2]. The critical factor that affects transformer life is the aging of the cellulose insulation, which is an irreversible process[3]. The Company experienced a growth phase in the 1960s and 1970s, and as a result there are a large number of transformer assets nearing their anticipated end of life. The replacement of these assets with consideration for future load growth, PCB mitigation concerns, and station consolidation opportunities will ensure reliable service well into the future.

The major transmission group is comprised of 17 terminal transformers with a collective transformation capacity of over 2,000 MVA. The median age of these units is currently 30 years. The chart below illustrates the large population 29 years or older due to system expansion in the late 1960s and early 1970s. This aging infrastructure will require reinvestment to maintain adequate levels of reliability. Terminal transformers will be replaced according to an assessment which will consider the asset health, reliability, risk of failure and the impact to the system if the transformer failed.

This program will begin in 2019 and replace a terminal transformer every five years until 2030. The expected cost is $32.02 million in the 2019-2031 period. Asset health data gathered during regular maintenance and inspections may precipitate advancing or delaying

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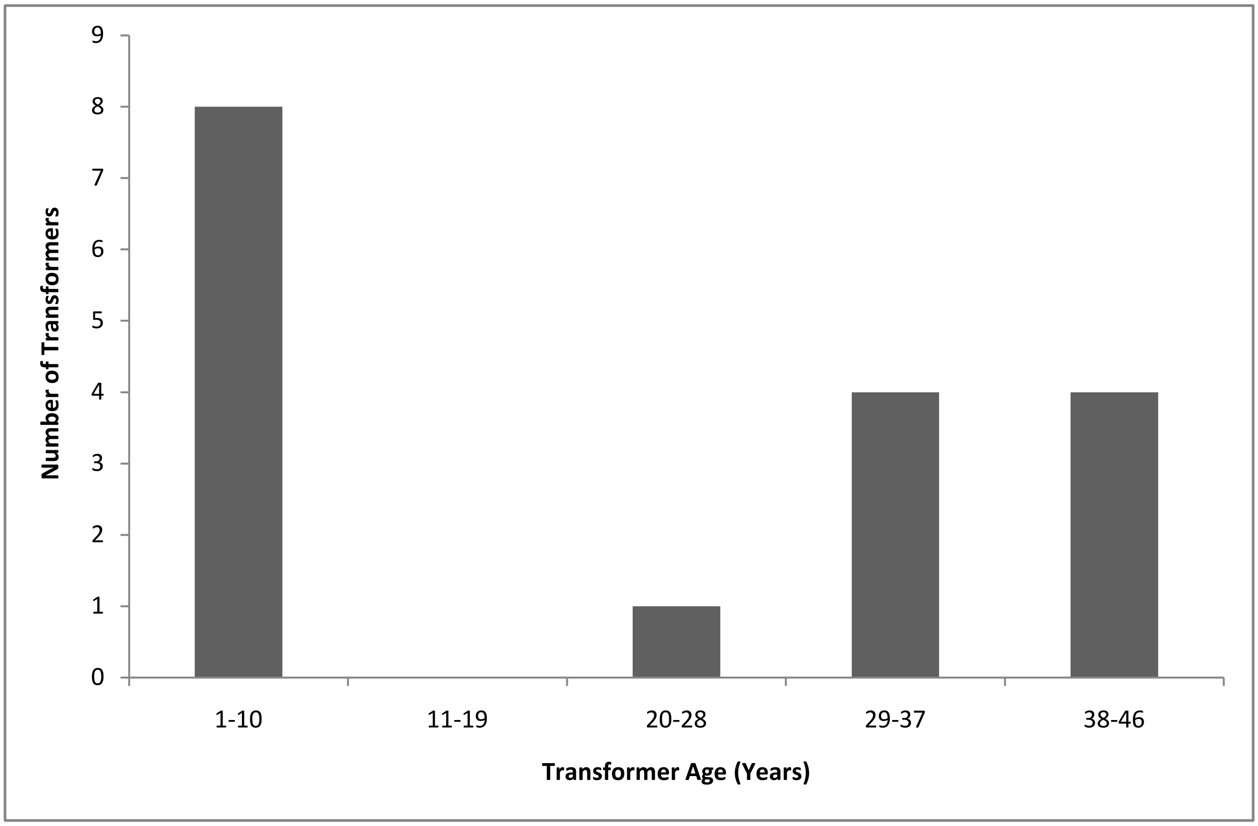
[2] Wijarn Wangee, "Quantifying Mobile Transformers for Southern Interior and Vancouver Island Regions Using Probabilistic Risk Assessment", Regional System Planning, SPPA, BCTC, http://transmission.bchydro.com/generator_interconnection/engineering_studies_data/studies/probabilistic_studies/selected_tech_reports.htm, February 24, 2011

[3] Dr. Dierk Bormann et al, "Service Handbook for Transformers", Switzerland, ABB Ltd, 2007, pp 240-242.

this schedule. This will be consistent with the proposed FortisBC Asset Management program.

Figure 2.10.5 (a) - Major Transmission Transformers



The replacement of transmission transformers in the North Okanagan will be performed on an as needed basis, with the existing transformation in the North Okanagan monitored and assessed consistent with the FortisBC Asset Management plan. In the next five year period, an additional 200 MVA transmission transformer is planned for the Kelowna area, as further described above in Section 2.8.4.

The completion of the Okanagan Transmission Reinforcement (OTR) project has increased the average health of the terminal transformer group on the South Okanagan. A new terminal transformer was added RG Anderson substation in 2010; the second transformer T1 is 35 years old. This older transformer will be monitored and assessed consistent with the Asset Management Plan.

There are three transformers in the Kootenay region which are older than 40 years. These include AS Mawdsley T1 and T2 transformers, and the Grand Forks Terminal T1 transformer - respectively 46, 40 and 46 years old.

The Grand Forks Terminal transformer addition would see a refurbished transformer, salvaged from the Oliver substation as part of the Okanagan Transmission Reinforcement project, installed at Grand Forks Terminal. This ex-Oliver transformer is 42 years old.

The General Wheeling Agreement between FortisBC and BC Hydro must be considered with the replacement of any of the above listed transformers. Currently, under the terms of this agreement, FortisBC must maintain a deemed capacity to transmit 120 MW from Trail to Oliver via the 11 Line path. This line is currently energized at 161 kV, with future plans to reduce the voltage to 138 kV. See the figure below for proposed configuration.

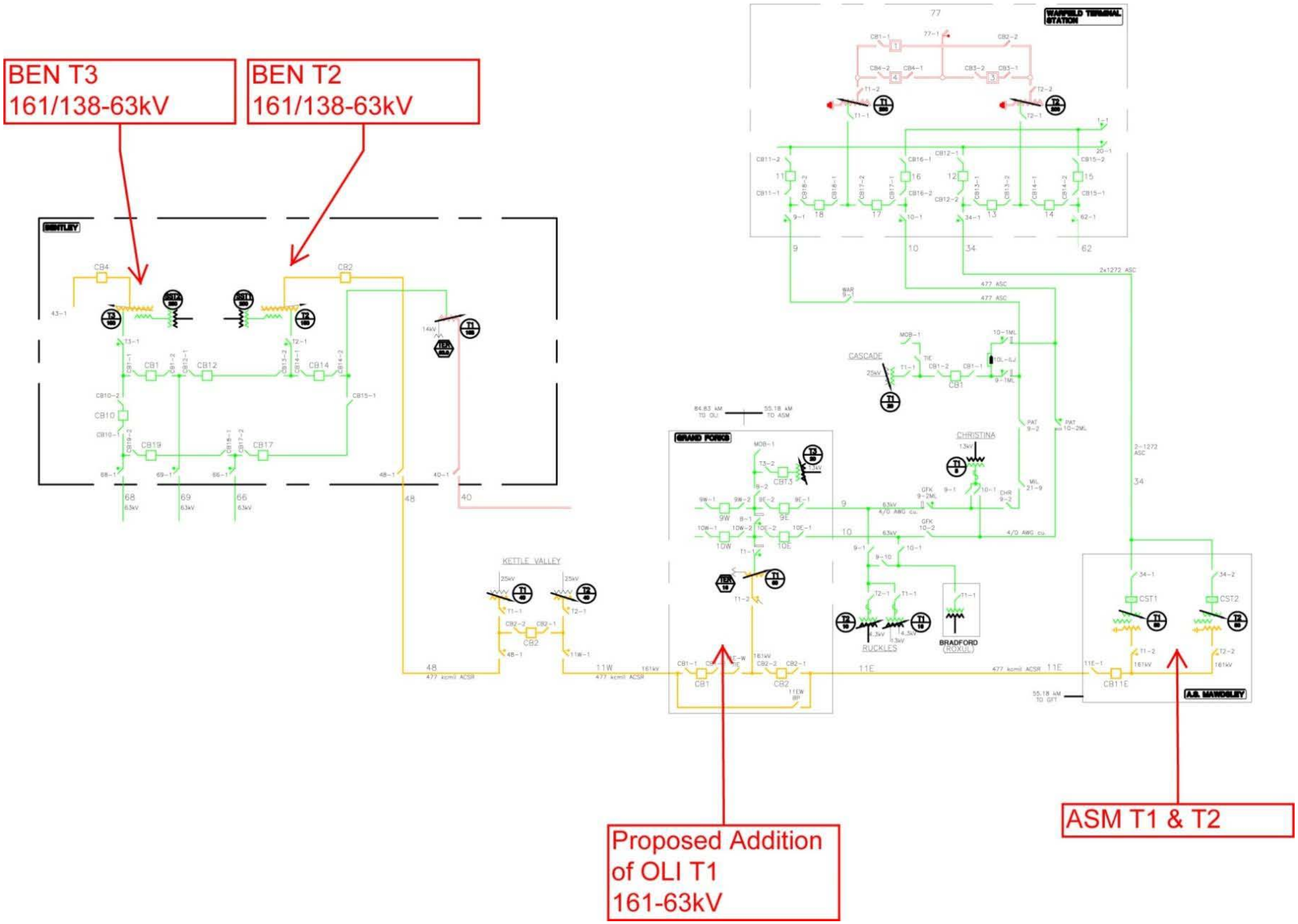
The configuration in Figure 2.10.5 (b) shows that the four oldest terminal transformers - RG Anderson T1, AS Mawdsley T1 and T2, and Grand Forks Terminal transformer T1 will be located in the same transmission corridor. The options for replacing the transformers will depend on the condition of the units, and possibly on the order of required replacement. There are two options for the eventual replacement of these units.

- Option 1 - Replace all units as they fail with dual voltage 161/138 kV units and convert the line to 138 kV when the last unit is replaced.
- Option 2 - Replace a failed AS Mawdsley transformer with Bentley Terminal transformer T2. This option is contingent on one of the Grand Forks Terminal transformers being replaced prior to this with a 161/138 - 63 kV unit, and a ring bus installed at the Bentley terminal station on the 138 kV bus. 11 Line would be converted from 161 kV to 138 kV.

Implementing Option 1 maintains the terms of the Wheeling Agreement with the replacement of two transformers (eventually both Grand Forks terminal transformers), the addition of the 138 kV ring bus at Bentley Terminal Station, and the relocation of Bentley Terminal transformer T2 to AS Mawdsley. The Kettle Valley station was built as a dual voltage 161/138 - 25 kV station for this possible eventuality.

The selection of Option 1 or 2 will depend on the order of transformer replacement and will be consistent with the proposed FortisBC Asset Management plan. The Boundary Area Supply project (section 2.8.12) to replace one of the AS Mawdsley transformers in 2020 will also influence the decision on the options listed above.

1 **Figure 2.10.5 (b) - RG Anderson, AS Mawdsley, Grand Forks Corridor**



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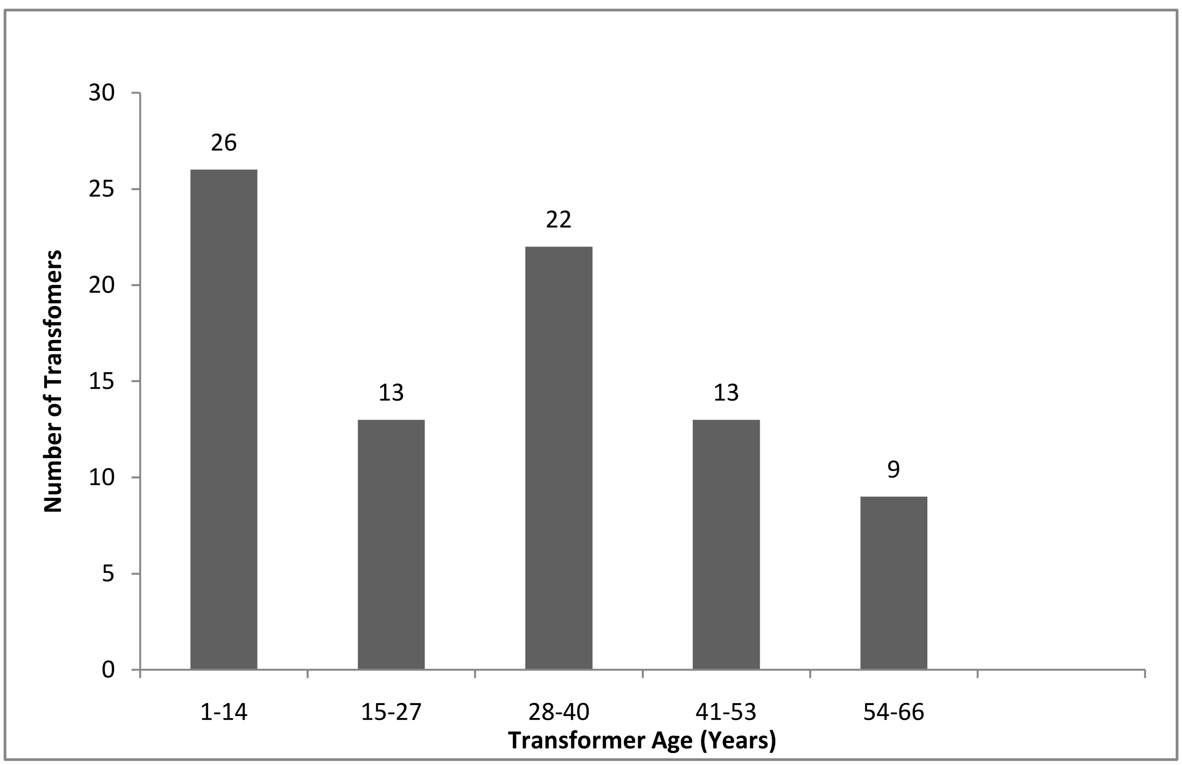
2.10.6 DISTRIBUTION SUBSTATION TRANSFORMER REPLACEMENTS

Aging distribution substation transformers will require reinvestment to maintain adequate levels of reliability. This program will address issues arising from aging plant and replace distribution transformers that have reached their end of life. Currently, the median age of this group of assets is 29 years. By 2031, the average age of the distribution transformer group will be 47 years. To reduce the risk of service interruption due to poor asset health, distribution transformers will be replaced starting in 2018 at a rate of one every three years. Coordination with growth planning will be pursued to identify areas where voltage conversions can result in station consolidation. In addition, PCB mitigation will be considered for these aging transformers, which may have contaminated bushings. Asset health data gathered during regular maintenance and inspections may precipitate advancing or delaying this schedule, and will be consistent with the proposed FortisBC Asset Management plan.

Figure 2.10.6 (a) - Distribution Transformer Age

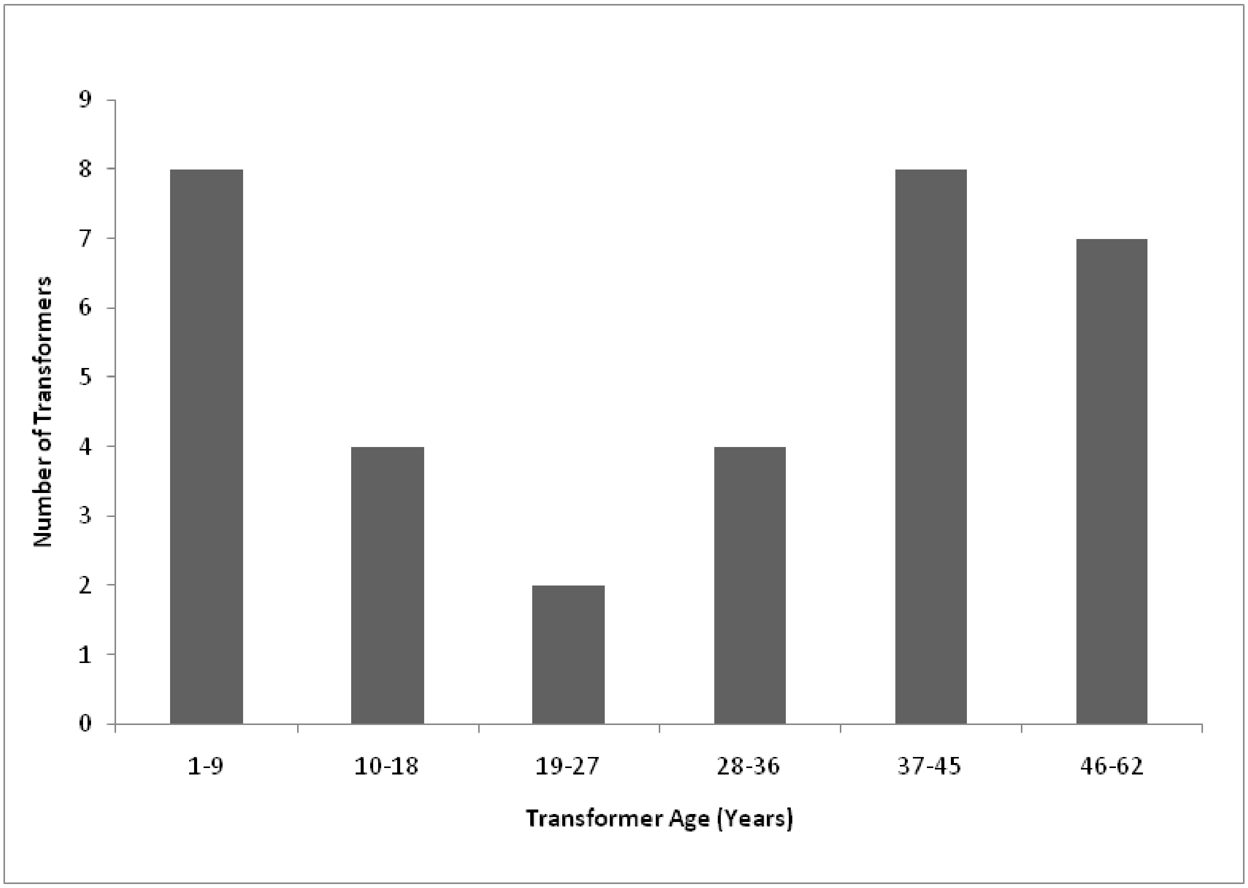


The North Okanagan region, encompassing Kelowna, has a relatively young population of transformers with an average age of 18 years. The Duck Lake transformer at 44 years is the exception. This transformer will be monitored and assessed as part of the proposed FortisBC Asset Management plan.

The South Okanagan area has a population of distribution transformers with an average age of 25 years. Over the course of the 20 year planning horizon, the median age of this group will climb to 46 years, meaning that half of the population of 23 transformers will be older than 46 years. The oldest four transformers are two 63/8 kV transformers at the Huth substation, the 63/13 kV transformer at Kaleden and the 63/8 kV transformer at Trout Creek. These transformers will be monitored and assessed consistent with the proposed FortisBC Asset Management plan. The Kaleden and Trout Creek transformers, along with the OK Falls (35 years old) and West Bench (33 years) units are slated to be replaced as part of the New Central Okanagan Substation project (refer to Section 2.8.22 for further information on this project).

The Kootenay region has the oldest population of transformers with an average age of 30 years and a median age of 35 years. There are a number of transformers which will be removed from service as a result of growth projects. The Playmor Substation 25 kV Distribution Transformer Addition project (section 2.8.15) will result in the removal of the 62 year old Tarrys Substation transformer from service. The Beaver Park South Solution project (section 2.8.8) will result in the removal of the 61 year old Hearns transformer and the 25 year old Fruitvale transformer. The remaining transformers in the area will be monitored and assessed in accordance with the proposed FortisBC Asset Management plan. This project is estimated to cost $10.98 million over the 2017-2028 timeframe.

1 **Figure 2.10.6 (b) - Kootenay Distribution Transformer Age**



3. DISTRIBUTION

FortisBC's distribution system consists of approximately 5,600 kilometres of overhead and underground infrastructure and covers an area of approximately 18,000 square kilometres. The distribution network is composed of approximately 146 feeder circuits which are operated at 25 kV and below. These circuits are supplied from distribution substations and provide service to the Company's residential, commercial and small industrial customers. Additionally, the Company provides wholesale distribution supplies to municipal electric utilities in Kelowna, Summerland, Penticton, Grand Forks and Nelson.

Some of the major components which make up the FortisBC distribution network include: support structures (wood/steel/concrete poles, cross-arms, insulators and guy wires); overhead conductors; underground cables; overhead and pad-mount distribution transformers; capacitor banks; switches; voltage regulators and circuit reclosers. To minimize costs and stores of spare parts, FortisBC has standardized on two nominal operating voltages for the distribution system; 13 kV is typically used for urban and some rural areas and 25 kV for rural areas where the higher voltage allows circuits to run longer distances. There remain some legacy 8 kV circuits in the Penticton/Summerland area; these are required primarily to provide service to municipal utilities which use that voltage. Over the previous decade, the Company has eliminated virtually all legacy 4 kV infrastructure with only two circuits remaining in Grand Forks to supply customers who require that voltage level.

The vintage of FortisBC's distribution infrastructure is highly variable. In some more rapidly-growing areas where load growth has required periodic capacity upgrades, the typical age of equipment may range from 40 years old to nearly new. In more rural areas where load growth is modest, there is still a considerable amount of overhead infrastructure which ranges from 50 to 100 years of age.

Distribution Voltage Conversion

FortisBC has previously implemented a number of distribution voltage conversion projects where the 4 kV or 13 kV distribution voltage traditionally used to serve customers was increased to 25 kV. These conversions have been part of long-term goal to move towards standardization on the 25 kV distribution voltage, where appropriate. In order to complete this conversion, lines and equipment must be upgraded to safely accommodate the new higher voltage, but the program provides several benefits. These include:

- **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 25 kV lines, 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.

Table 3.0 - Distribution Projects

	Distribution Growth	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	New Connects System Wide	11,057	10,780	11,446	11,536	12,076	211,955
2	Small Growth Projects	1,069	888	1,321	1,752	1,523	26,841
3	Distribution Unplanned Growth	924	930	1,031	1,033	1,044	18,682
4	Glenmerry Feeder 2-Glenmerry Feeder 1 Tie Line	596	-	-	-	-	-
5	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	-	1,161	-	-	-	-
6	Hollywood Feeder 5 Upgrades	-	-	1,172	-	-	-
7	Kaleden Feeder 1 Capacity Upgrades	-	-	1,330	-	-	-
8	Grand Forks Terminal Feeder Addition	-	-	-	-	4,530	-
9	Kettle Valley to Nk'Mip Distribution Tie	-	-	-	-	-	7,699
10	DG Bell Feeder 4 Addition	-	-	-	-	-	2,115
11	**Total Distribution Growth**	**13,646**	**13,759**	**16,300**	**14,320**	**19,172**	**267,293**
12							
13	**Distribution Sustainment**						
14	41 Line Salvage and Distribution Underbuild Rehabilitation	2,067	-	-	-	-	-
15	Distribution Line Condition Assessment	1,410	1,398	1,530	1,509	1,569	27,970
16	Distribution Line Rehabilitation	5,298	3,517	3,592	3,840	3,865	69,449
17	Distribution Line Rebuilds	1,679	1,660	2,214	2,251	2,335	41,153
18	Distribution Urgent Repairs	2,411	2,315	2,480	2,606	2,605	46,384
19	Forced Upgrades and Lines Moves	2,012	2,413	2,382	2,144	2,462	42,572
20	Distribution Line Small Planned Capital	726	826	853	867	870	15,719
21	Environmental Compliance (PCB Mitigation)	-	-	-	-	-	16,386
22	**Total Distribution Sustainment**	**15,603**	**12,129**	**13,051**	**13,216**	**13,706**	259,634
23	**Total Distribution Projects**	**29,249**	**25,889**	**29,351**	**27,537**	**32,878**	526,927

For the purposes of this planning exercise, two timeframes were used for reviewing distribution projects. First, detailed planning studies and reviews were developed to identify projects required within the 2012 to 2016 timeframe. Distribution projects beyond that timeframe have only been scheduled in high-level terms since these projects are sensitive to localized developments and load growth. As a result, the in-service date uncertainty for these projects is greater for those projects beyond the five year horizon.

The following projects are required to address capacity, reliability and safety issues related to the FortisBC distribution system and to ensure that all customers continue to receive safe, reliable and cost-effective electric service.

3.1 Distribution Growth

The Distribution Growth projects are separated into two main categories; the Small Growth projects including all capacity related projects under $500,000, and all other distribution upgrade projects that are over $500,000. Each of the projects identified have been through a planning procedure and are necessary to continue to provide reliable service. The planning criteria by which these projects were evaluated are discussed in the Distribution Planning Manual at Appendix H.

3.1.1 NEW CONNECTS SYSTEM WIDE

This project includes the installation of new electric services requiring additions to FortisBC overhead or underground distribution facilities. These capital expenditures allow FortisBC to meet its obligation to provide reliable service to customers in the service area. This project will also fund any "forced upgrade" costs associated with upgrading FortisBC facilities to provide service for the extension or drop service.

Capital expenditures are net of customer contributions.

Table 3.1.1 - Distribution New Connects System Wide

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	8,861	12,845	8,782	8,660	8,758	11,057	10,780	11,446	11,536	12,076	211,955

3.1.2 SMALL GROWTH PROJECTS

The Small Growth Projects are projects that relate to capacity upgrades, feeder ties, and load transfers and are required to keep pace with normal load growth on the distribution system and to ensure continuing acceptable standards of service. These service standards include operation of facilities at or below normal continuous thermal limits; voltage consistent with Canadian Standards Association (CSA) recommended levels and short circuit levels in a range to allow for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system. The small growth projects are defined by a distribution capacity related upgrade under $500,000.

Table 3.1.2 - Distribution Small Growth Projects

Year	2012	2013	2014	2015	2016	2017-31
	($000s)					
Cost	1,069	888	1,321	1,752	1,523	26,841

3.1.3 DISTRIBUTION UNPLANNED GROWTH

Capacity upgrades and line extensions are required periodically to keep pace with normal load growth on the distribution system and to ensure continuing acceptable standards of service. These service standards include operation of facilities at or below normal continuous thermal limits; voltage consistent with CSA recommended levels and short circuit levels in a range to allow for safe operation of the electrical system. Capacity increases must also be designed to provide sufficient redundancy to maintain supply during planned and unplanned outages on the distribution system.

This program includes service upgrades, voltage regulation, tie to accommodate load splitting, single-phase to three-phase upgrades and conductor upgrades that are necessary due to load growth, but were unforeseen at the time the expenditure plan was prepared.

Table 3.1.3 - Distribution Unplanned Growth

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,065	834	604	750	981	924	930	1,031	1,033	1,044	18,682

3.1.4 GLENMERRY FEEDER 2 TO GLENMERRY FEEDER 1 TIE LINE

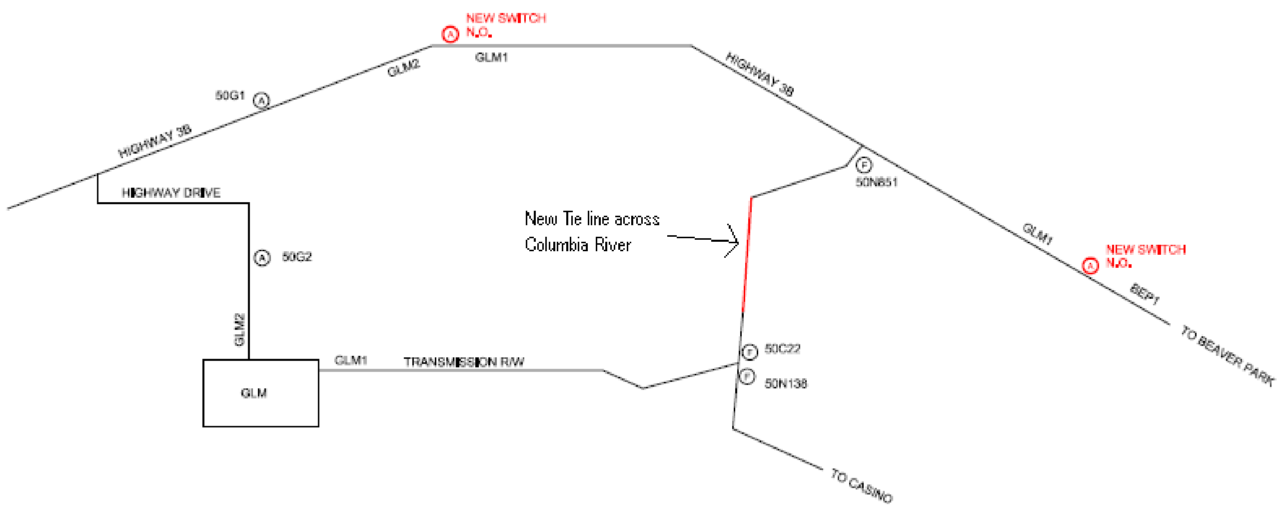
Glenmerry Feeder 1 is a short, lightly loaded feeder that supplies the community of Casino near Trail, British Columbia. It has 1.8 kilometres of three-phase line and at the 1.6 kilometre mark has a 5.5 kilometre single-phase tap. With a forecast 2011 winter peak of 0.281 MVA this feeder is underutilized and not operating in an optimum configuration.

The Fruitvale substation transformer is currently exceeding the nameplate capacity rating during peak conditions. In order to alleviate this overload, a 2010 project transferred load from Fruitvale Feeder 1 onto Beaver Park Feeder 2, and then from Beaver Park Feeder 1 to Glenmerry Feeder 2. Also during 2010 however, two large developments (Waneta Expansion and Firebird Technologies) took place on Beaver Park Feeder 2 and will drive the Beaver Park transformer into an overloaded condition in 2011. Load transfer between Beaver Park Feeder 1 and Glenmerry Feeder 2 will allow the Beaver Park T1 transformer to operate below its nameplate rating, but the transfer will cause Glenmerry Feeder 2 to operate outside of its normal rated limits (400 amp).

This project involves the construction of a river crossing to extend the Glenmerry Feeder 1 across the Columbia River to tie into Glenmerry Feeder 2 and allow load transfer from Glenmerry Feeder 2 to Glenmerry Feeder 1. The project will offload feeders Glenmerry

Feeder 2 and Beaver Park Feeder 1 and in turn take enough loads off Beaver Park T1 transformer to push the need for a major capacity increase project out another 8-10 years. Refer to single line diagram Figure 3.1.4 below.

Figure 3.1.4 - Glenmerry Feeder 2 and Feeder 1 Tie Line Single Line Diagram



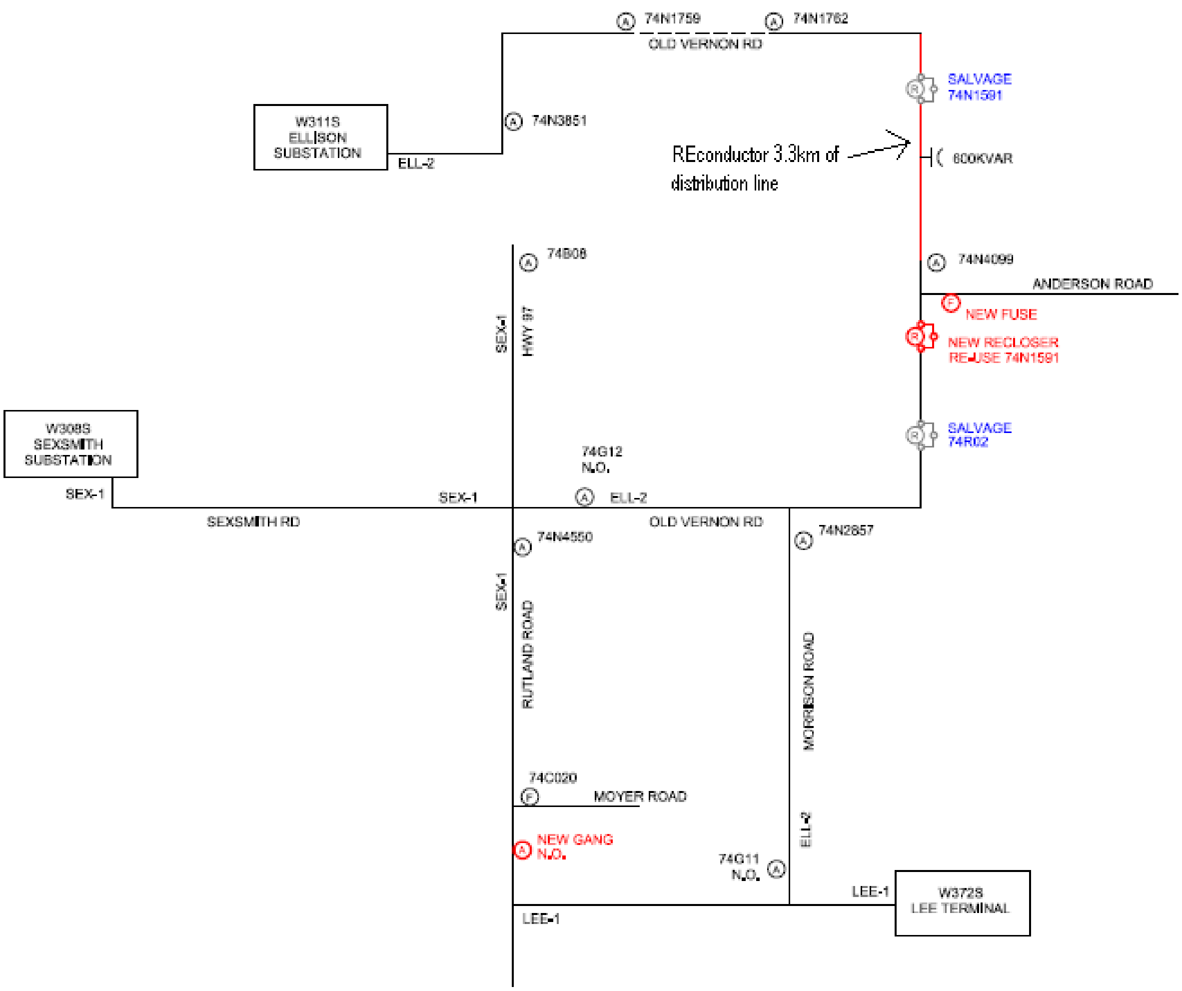
This project is estimated to cost $0.60 million with a projected start date of 2012 and an in-service date the same year.

3.1.5 ELLISON FEEDER 2 TO SEXSMITH FEEDER 1 TIE

The Ellison substation was brought online in the winter of 2009, helping to considerably reduce the load on the Sexsmith and Duck Lake substations. Since then some of the Glenmore load was transferred to Sexsmith in order to relieve the Glenmore station of overloading. The Sexsmith T1 transformer is now forecast to overload within the five-year timeframe. The plan is to reconductor along Old Vernon Road to a larger conductor to complete the large capacity feeder tie between Ellison Feeder 2 and Sexsmith Feeder 1. This enables a load transfer onto Ellison from Sexsmith which delays the much more costly need for a second transformer at Sexsmith by several years. The feeder tie upgrade also enables more offloading of the FA Lee distribution load which resides on the tertiary windings of the FA Lee terminal transformers.

Figure 3.1.5 is a single line diagram showing visual representation of the upgrades required and load transfer that will occur.

Figure 3.1.5 - Ellison Feeder 2 to Sexsmith Feeder 1 Tie



This project is estimated to cost $1.16 million with a projected start date of 2013 and a necessary in-service date of 2013.

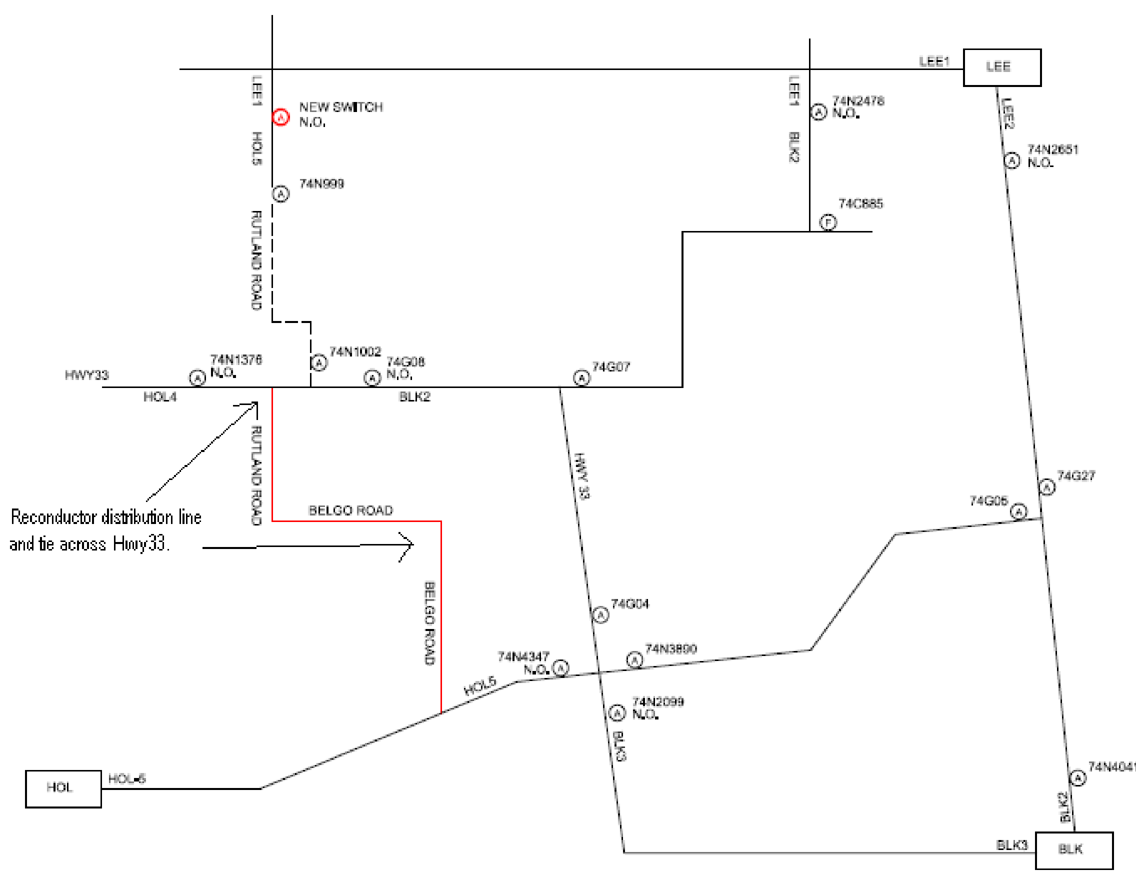
3.1.6 HOLLYWOOD FEEDER 5 UPGRADES

FA Lee Feeder 1 is currently served by a delta tertiary winding on a 230 kV/138 kV transformer at FA Lee Terminal station which is not standard practice. Normally these tertiary windings are reserved for supplying power to the substation facilities only. Faults on the existing distribution feeders are typically high in value and can potentially damage the transformer windings resulting in transformer failure. Considering that these transformers have the task of providing bulk power to the entire Kelowna area, and considering that remediation methods exist, FortisBC sees merit in reducing the transformer failure risk.

During the 2008 - 2010 timeframe, the Company constructed the Black Mountain and Ellison substations to help offload the FA Lee distribution load. Much of the distribution load has already been removed but there are still opportunities involving distribution upgrades that will result in the transfer of more load. When load growth justifies it, which is currently forecast for around 2018, an FA Lee distribution transformer will be installed and all load on the tertiary windings will be eliminated. However, the current strategy is to offload as much FA Lee distribution load as possible to the existing distribution system to delay the large capital expenditure of the new distribution source.

This project involves the reconductoring of approximately 1.5 kilometres of Hollywood Feeder 5 along Belgo Road to Rutland Road, and then along Rutland Road to Highway 33. This will permit the transfer of load from FA Lee Feeder 1 to other adjacent feeders. Figure 3.1.6 below shows a single line diagram detailing the proposed reconductoring of Hollywood Feeder 5.

Figure 3.1.6 - Hollywood Feeder 5 Upgrades



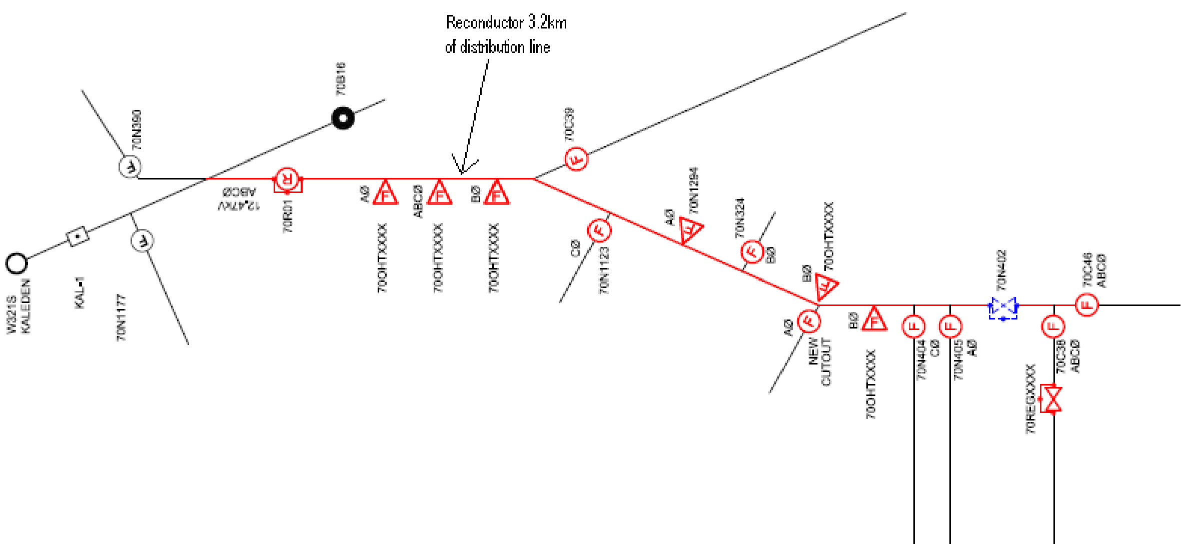
This project is estimated to cost $1.17 million with a projected start date of 2014 and a necessary in-service date of 2014.

3.1.7 KALEDEN FEEDER 1 CAPACITY UPGRADES

Kaleden Feeder 1 has a long radial tap from the main feeder that consists of small conductor. Currently there is a proposed development for a golf course together with a number of irrigation pumps near the end of this line. System planning studies indicate that unless action is taken, customers at the end of the line by the Twin Lakes golf course will experience below standard voltage levels as this development occurs around the 2014 timeframe. The existing 200A regulator bank 70N402 is forecast to overload as well.

This project will alleviate voltage problems and regulator overloading by reconductoring a 3.2 kilometre section of this line to a larger conductor and relocating the regulator bank to an optimum location. An evaluation of options on this feeder indicates that this is the lowest cost alternative to solve the long term problems. Please refer to Figure 3.1.7 below which shows the Kaleden Feeder 1 Capacity Upgrades as a single line diagram.

Figure 3.1.7 - Kaleden Feeder 1 Capacity Upgrades



This project is estimated to cost $1.33 million with a projected start date of 2014 and a necessary in-service date of 2014.

3.1.8 GRAND FORKS TERMINAL FEEDER ADDITION

Christina Lake T1 transformer is forecast to exceed its nominal nameplate capacity of 5 MVA in winter 2016. Because the load supplied from this station is relatively low and the customer growth in the area is not very high, the Company did an analysis to determine whether offloading this station would be possible with existing assets or with minimal investment to support a future plan.

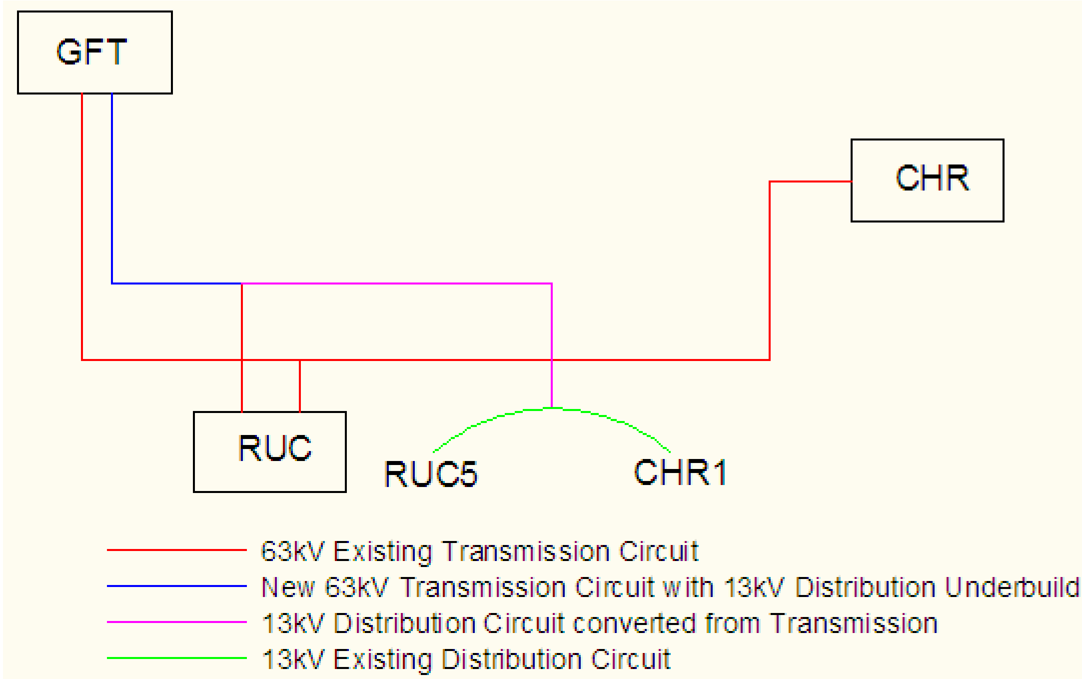
A location approximately 7 kilometres east of Grand Forks Terminal station on the 9 Line/10 Line corridor provided an ideal location for a new express feeder out of Grand Forks Terminal station to interconnect with Ruckles Feeder 5 and Christina Lake Feeder 1. By interconnecting at this location, 2.2 MVA and 1 MVA could be offloaded from both Ruckles Feeder 5 and Christina Lake Feeder 1 respectively with the added support of a regulator. This project will therefore eliminate the need to upgrade Christina Lake T1 transformer from a capacity perspective until beyond the 20-year planning horizon.

9 Line and 10 Line will no longer be required between Rossland and Christina Lake provided the Grand Forks Terminal station transformer installation project, as discussed in section 2.8.3 above, is implemented. As part of that project, Christina Lake will be supplied from only one line out of Grand Forks Terminal station and therefore the remaining line between Grand Forks Terminal station's tap point (approximately three kilometres east of Grand Forks) to Ruckles and Christina Lake can be decommissioned or rehabilitated as distribution.

To create an express feeder to the interconnection point, underbuild would need to be installed for the first three kilometres on either 9 Line or 10 Line and the redundant transmission line between the Ruckles tap point with the interconnection point converted to distribution. As both 9 Line and 10 Line from Grand Forks Terminal station to the Ruckles tap point are in poor condition and neither circuit has sufficient clearance to allow for a distribution underbuild circuit to be installed, this project was estimated based on building a new circuit from Grand Forks Terminal station to the Ruckles tap point and then converting the redundant line between the tap point and the interconnection point to distribution.

This project falls in line with the Company's 20 year plan to have a 25 kV express feeder out of Grand Forks Terminal station to offload Ruckles and Christina Lake completely. This project puts the line in place (with a few exceptions), but the conversion would not occur until Christina Lake or Ruckles is once again overloaded.

Figure 3.1.8 - Grand Forks Terminal Feeder Addition Final Arrangement



This project is estimated to cost $4.53 million with a projected start date of 2016 and a necessary in-service date of 2016.

3.1.9 KETTLE VALLEY TO NK'MIP DISTRIBUTION TIE

This project is required to tie the Kettle Valley feeder to the Nk'Mip distribution at 25 kV to improve reliability of the area. This project will be done when the load growth on Anarchist Mountain develops to the point where there are enough customers to justify tying the two feeders together. This project would also include a small step-down transformer site in order to enable the two different voltages to be tied together.

This project is estimated to cost $7.70 million with a projected start date of 2030.

3.1.10 DG BELL FEEDER ADDITION

Currently the DG Bell station has three feeders with a spare breaker available for a future feeder. DG Bell Feeder 2 is forecast to overload in 2012. The original planned solution was to make use of the spare breaker and add a fourth feeder to the station in order to offload the existing load. This project has now been deferred to sometime outside of the five year window because the capacity issues identified on DG Bell Feeder 2 will be alleviated by the DG Bell Feeder 1 and DG Bell Feeder 2 upgrade project identified in the Small Growth Project list in 2012 (2012 - 2013 Revenue Requirements, Tab 6 [2012 - 13 Capital

Expenditure Plan], section 4.1.2.1). This is a more cost effective approach to this problem and defers the larger capital expenditure of adding a fourth feeder. However, eventually there will be a requirement for a fourth feeder from the DG Bell Terminal station in order to provide relief to the existing DG Bell feeders and continue to provide reliable service to the south Mission area.

This project is estimated to cost $2.12 million with a projected start date of 2018 and a necessary in-service date of 2018.

3.2 Distribution Sustainment

Table 3.2 - Distribution Sustainment Expenditures

	Distribution Sustainment	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	41 Line Salvage and Distribution Underbuild Rehabilitation	2,067	-	-	-	-	-
2	Distribution Line Condition Assessment	1,410	1,398	1,530	1,509	1,569	27,970
3	Distribution Line Rehabilitation	5,298	3,517	3,592	3,840	3,865	69,449
4	Distribution Line Rebuilds	1,679	1,660	2,214	2,251	2,335	41,153
5	Distribution Urgent Repairs	2,411	2,315	2,480	2,606	2,605	46,384
6	Forced Upgrades and Lines Moves	2,012	2,413	2,382	2,144	2,462	42,572
7	Distribution Line Small Planned Capital	726	826	853	867	870	15,719
8	Environmental Compliance (PCB Mitigation)	-	-	-	-	-	16,386
9	**Total Distribution Sustainment**	**15,603**	**12,129**	**13,051**	**13,216**	**13,706**	259,634

3.2.1 41 LINE SALVAGE AND DISTRIBUTION UNDERBUILD REHABILITATION

41 Line will no longer be required by the end of 2011 after the Okanagan Transmission Reinforcement and the Huth Bus Reconfiguration projects are complete. 41 Line is an older vintage line and is in poor condition (approximately $850,000 worth of rehabilitation is required from a recent condition assessment). 41 Line has distribution underbuild along most of its length so even though the transmission circuit can be salvaged, the distribution underbuild must remain.

The scope of this project is to salvage the 41 Line transmission conductor and structures that do not have distribution underbuild along the full right of way while keeping the distribution underbuild poles in place. The purpose of this project is to salvage out the abandoned plant that poses a safety risk. Recently there have been many concerns with copper theft and 41 Line would be a prime target once out of service. The safety risk would be that the distribution underbuild would remain live.

Based on the expenditures required to rehabilitate the line and continue to maintain it, the Company is proposing to salvage a portion of the 41 Line transmission conductor and structures that do not have distribution underbuild along the full right of way while converting the remaining sections with distribution underbuild to a standalone distribution feeder (no transmission overbuild).There is a small section of 41 Line, less than 10 percent of the line length, that will remain to be reused as a distribution feeder tie between the Kaleden substation and the OK Falls substation. Currently there is no backup capability to the Kaleden feeder as it operates radially. This project will enable the offload of the Kaleden station to the OK Falls station in the event of a distribution contingency, resulting in improved reliability to customers served by the Kaleden feeder.

This project is estimated to cost $2.07 million with a projected start date of 2012 and a necessary in-service date of 2012.

3.2.2 DISTRIBUTION LINE CONDITION ASSESSMENT

The Distribution Line Condition Assessment program is based on an eight-year cycle of patrolling and testing all of FortisBC's distribution line facilities. The program consists of a pole test and treat and a condition assessment. The test and treat involves drilling test holes in each pole to confirm the condition of the pole, addition of a pole treatment to reduce internal rot in the pole, and placement of a pole wrap to reduce surface rot on the pole at the ground line. The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The test and treat program is aimed at the section of pole at the ground level and below on all the poles. The condition assessment is aimed at the portion of the pole above the ground line which inspects the pole top condition, anchoring, crossarms, and insulators. If anything fails its inspection during the condition assessment then the deficiency is documented and will be corrected under the following year's rehabilitation budget.

The detailed methods and criteria applied in the distribution assessment program are further described in Appendix I. The program cost forecasts are based on rolling average estimates combined with the Company's knowledge of the distribution lines expected to be assessed. 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.

Worst Performing Feeders Program

As outlined in the response to BCUC IR 59.1.1 (Exhibit B-3) regarding FortisBC's 2010 Annual Review and 2011 Revenue Requirements, FortisBC does not have a specific program that defines distribution projects purely based on reliability statistics.

A Worst Performing Feeders Program involves, identifying the poorest performing feeders and the cause(s) of the poor performance, developing and implementing an action plan to correct the problems and assessing the effectiveness (improved reliability and cost-effectiveness) the action plan had on the system. The poorest performing feeder is identified using reliability statistics derived from the average duration of customer interruptions (SAIDI) and the average frequency off customers interrupted (SAIFI). A Worst Performing Feeders Program enables a focused allocation of resources on specific feeders to address system reliability improvements by identifying the worst performing areas of the system using defined criteria, identifying causes for poor performance, and identifying and implementing a cost-effective solution.

FortisBC currently implements a slightly different version of a worst performing feeder program. The Company implements an eight-year condition assessment/rehabilitation cycle on all distribution circuits to ensure the assets are sound and unlikely of failing. Every year the distribution system is upgraded with new reclosers/switches or maintenance to correct deficiencies brought forward from operations using the unplanned growth and/or small planned capital budgets. Between these processes and the brushing program the Company is continually improving the worst performing feeders throughout the service territory.

Table 3.2.2 - Distribution Line Condition Assessment

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	938	692	659	605	992	1,410	1,398	1,530	1,509	1,569	27,970

3.2.3 DISTRIBUTION LINE REHABILITATION

The project involves expenditures for structural stabilization of multiple distribution lines based on the detailed Distribution Line Condition Assessment program which is based on an eight-year cycle.

The key stakeholders in this project are the property owners and the general public along the route of the subject lines. The interest of property owners and the general public relates to the potential for property damage or personal injury in the event that the lines failed mechanically. A proactive preventive maintenance program that minimizes the risk of structural failure best serves their interests.

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

Table 3.2.3 – Distribution Line Rehabilitation

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,375	3,727	3,294	3,086	2,303	5,298	3,517	3,592	3,840	3,865	69,449

3.2.4 DISTRIBUTION LINE REBUILDS

On a regular basis Distribution Planning Engineers undertake site assessments of the distribution system in their respective areas. They review the system from a safety, reliability and capacity perspective. Any sections of line that have deficiencies are identified and a proactive project is established to correct the problem. This project involves the replacement of aged and deteriorated equipment. Items include rebuilding failing overhead and underground conductor, replacing rotted poles and platforms, replacing leaking transformers, and installing ground grids at ungrounded services. These deficiencies are identified through site assessments and normal daily operations.

Table 3.2.4 - Distribution Line Rebuilds

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,528	1,310	1,371	1,240	2,071	1,679	1,660	2,214	2,251	2,335	41,153

3.2.5 DISTRIBUTION LINE URGENT REPAIRS

Component failures on the distribution system due to inclement weather, defective equipment, animal intrusions, vandalism, abnormal operating conditions, vehicle collisions and human error cause outages or present risks that must be addressed in an expedient manner to ensure that employee and public safety is not at risk and electrical service continuity is maintained. This project is ongoing and involves the repair or replacement of distribution equipment that fail in-service due to severe weather, vandalism or for other unexpected urgent reasons.

Table 3.2.5 - Distribution Line Urgent Repairs

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	2,117	3,258	2,370	2,008	2,842	2,411	2,315	2,480	2,606	2,605	46,384

3.2.6 FORCED UPGRADES AND LINE MOVES

This program is required to complete distribution upgrades driven by third-party requests. These requests can be a result of highway/road widening or improvements, miscellaneous customer line moves or an upgrade resulting from new customer connects.

Relocation of distribution lines due to highway/road widening or improvements will be initiated based on requests from the BC Ministry of Transportation and Infrastructure and/or municipalities. Miscellaneous customer line move requests where FortisBC does not have sufficient land rights for the facilities located on customer property are also included in this project.

- Requests which are received from governing authorities (e.g. Ministry of Transportation and Infrastructure or municipalities) within the FortisBC service area to relocate distribution lines located on road allowance or highway rights of way to accommodate road widening or improvements.
- Customer requests to move FortisBC distribution line facilities.
- Requests to satisfy issues where FortisBC does not have sufficient land rights for the distribution line facilities located on customer property. In each case, alternatives will be considered and the most cost effective solution will be selected. This includes having the FortisBC land department attempt to negotiate land rights for non-easement issues.
- Third-party utility requests for upgrade of FortisBC distribution line plant to accommodate a shared use arrangement.

Table 3.2.6 - Forced Upgrades and Line Moves

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,573	385	2,016	3,768	1,572	2,012	2,413	2,382	2,144	2,462	42,572

3.2.7 DISTRIBUTION SMALL PLANNED CAPITAL

This program is similar to the Distribution Condition Assessment and Rehabilitation programs but captures off-cycle work required to keep the distribution lines safe and reliable. This program involves expenditures for repairs that are identified on the distribution system as a result of storm damage, clearance problems, aging equipment, reports by powerline technicians and other inspections outside of the normal assessment cycle. The repairs to address these concerns are required to maintain a safe and reliable distribution system and are generally non-urgent in nature and are normally completed within one year of the initial request. The planned expenditures for this program are based on historical information.

Table 3.2.7 - Distribution Small Planned Capital

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,080	572	642	868	805	726	826	853	867	870	15,719

3.2.8 ENVIRONMENTAL COMPLIANCE (PCB MITIGATION)

The *Canadian Environmental Protection Act PCB Regulations (SOR/2008-273)* came into effect on September 5, 2008. The purpose of the *PCB Regulations* is to improve the protection of Canada's environment and the health of Canadians by minimizing the risks posed by the use, storage and release of polychlorinated biphenyls (PCBs) and by accelerating the elimination of these substances.

By the end of 2014, FortisBC will meet regulations for all substation equipment including small volume units such as bushings and instrument transformers. Expenditures of approximately $27.40 million will be required to meet the station equipment compliance requirement by December 31, 2014.

Compliance will be required by 2025 for all distribution oil-filled equipment to less than 50 mg/kg PCB. Planning and testing for the future removal and destruction of PCB-contaminated overhead distribution equipment will start in 2015, based on best management practice and experience gained in the earlier PCB program. FortisBC expects to spend $16.40 million from 2017 to 2025 to meet these regulations.

4. TELECOMMUNICATIONS, SCADA PROTECTION AND CONTROL

4.1 System Overview

FortisBC owns, maintains and operates an extensive communications network in support of the safe, reliable and efficient operation of the electric grid throughout the Company's service area. Over 100 locations including 9 terminal stations, 52 distribution and switching stations, 4 generation plants, 16 mountain-top radio repeaters and 15 office locations are connected to the network. As well, the company owns and operates communications equipment at a number of third-party substations and generation sites that are necessary to operate the interconnected system. Communication links are also provided between neighbouring entities such as BC Hydro, Columbia Power Corporation, and Teck Metals Ltd. for the exchange of operational data and protection circuits.

Specifically, this communications network facilitates the following applications for the transmission, distribution, generation and corporate divisions of the Company:

- Teleprotection (Transmission lines)
- Asset monitoring and control
- Revenue metering
- Remedial Action Schemes (RAS)
- Security
- Phone services
- Very High Frequency (VHF) radio
- Corporate Intranet/Internet

In addition to the applications listed above, other traffic that is expected to be added to the FortisBC network in the future include:

- Video surveillance
- Advanced Metering Infrastructure (AMI)
- Demand Side Management / Demand Response control to customers (DR)
- Distribution automation and protection
- Smart Grid
- Transformer condition monitoring

A variety of telecommunications transport systems are used, depending on technical requirements, economics and system reliability requirements. These include powerline carrier, fibre-optic cable, copper pairs, third-party leased lines, cellular voice/data, and radio

(VHF, microwave, spread spectrum and packet radio). The telecommunications system is an integral component in the protection relaying system, Remedial Action Schemes, substation operations and control, and generation dispatch systems. It also provides a low-cost alternative to the public network for internal business data and some voice traffic.

4.2 Current System Deficiencies

The 2005 Master Plan investigated and outlined in detail a number of FortisBC telecommunications system deficiencies. Since that time, several of the identified items have been rectified and the risks mitigated including:

- Removal of several powerline communication (PLC) links;
- Build out of fibre-optic network; and
- VHF narrowbanding.

On the other hand, a number of deficiencies still exist, and the projects outlined below are designed to address and eliminate these, in addition to providing the needed communications resources for the future.

4.2.1 FIBRE OPTIC BACKBONE INFRASTRUCTURE

Most electric utilities operate some form of operational communications network which is used to carry critical operational traffic such as teleprotection communications, SCADA remote control and monitoring data and Remedial Action Scheme communications. Due to safety, reliability and security requirements these systems are typically owned and maintained by the utility to ensure that the communications network has a very high availability and is highly resistant to external disruptions.

For example, in a study and survey published by the Utilities Telecom Council it was noted that: *"Most respondents indicated that reliability must reach five nines, or that the network must remain operational 99.999% of the time."* [4] This level of reliability translates into the requirement that any given communications path must not experience more than 5.3 minutes of total outage time in a year. Indeed, a number of utility respondents required an even higher level of service (99.9999 percent) which corresponds to no more than 32

[4] "A STUDY OF UTILITY COMMUNICATIONS NEEDS - Key Factors That Impact Utility Communications Networks", September 2010 - Utilities Telecom Council

seconds of outage time per year. These are very stringent requirements and few (if any) third-party telecommunications providers are able to offer and commit to this level of service.

Two communications technologies capable of providing the required bandwidth and reliability are high-bandwidth microwave and fibre-optic communications. Each has advantages and disadvantages. For a given bandwidth requirement, microwave communications tends to be more appropriate for spanning very long distances, whereas fibre-optic cable is generally more suitable for shorter path lengths.

FortisBC's preferred method of communications technology is fibre-optic communications. This technology was first deployed in the mid 1990s and the Company has continued to extend and enhance its fibre-optic network as required to support recent transmission infrastructure upgrades. Fibre-optic communications offers numerous advantages from a utility point-of-view, including essentially unlimited bandwidth, extremely high reliability and security, relatively low installation costs and low ongoing maintenance costs.

From a physical infrastructure point of view the current FortisBC fibre-optic network is composed of two separate, linear fibre-optic routes, one in the Okanagan and one in the Kootenay region.

As can be seen in the following diagram the System Control Centre, located in Warfield, is connected directly to the Kootenay fibre system but there is no infrastructure in place to interconnect the Okanagan system. FortisBC presently has access to two digital circuits between the Vaseux Lake Terminal station and BC Hydro's Kootenay Canal Generating Station provided by a third-party to facilitate this backhaul.

Figure 4.2.1 - FortisBC Fibre Path

Note: Diagram shows the FortisBC fibre path (green) between BC Hydro's Vernon Terminal and the Grand Forks Terminal; and between the System Control Center and the Corra Linn Dam. Fibre terminus stations and splice points have been included. A leased link (yellow) between Vaseux Lake Terminal and BC Hydro's Kootenay Canal is also shown.

This configuration is not desirable for the following reasons:

- FortisBC has no control over the availability or reliability of third-party providers' circuits. Generally, standard service level agreements will not provide guaranteed availability sufficient to achieve end to end up times specified in WECC standards or in FortisBC's internal policies. Furthermore, FortisBC believes that in an emergency situation, where it is imperative that the power system continues to operate, a third-party will not prioritize its work based on the needs of FortisBC to the detriment of this critical infrastructure.
- Bandwidth is constrained. It is anticipated that the amount of bandwidth needed in the future will continue to increase as new applications in security, automation, metering, teleprotection and others are deployed. The capacity of the present link

between the systems will not be sufficient for the growth in new applications and additions to the system.

- There is no guarantee of lease. Many utilities are exploring deploying next generation networks based on packet switching technology which may or may not be capable of carrying legacy time-division multiplexing (TDM) traffic with the reliability of the current Synchronous Optical Network (SONET) systems. The provider of the circuits is expected to begin their migration sooner than FortisBC and this could impact the leased circuits and the ability to monitor and control the Okanagan systems from the control centre.

4.2.2 NO PATH REDUNDANCY ON BACKBONE

Figure 4.2.1 above also illustrates the absence of path or route diversity on the FortisBC backbone system. Even without path redundancy, multiple fibres can be used to achieve equipment redundancy, and this has proven to be a robust solution so far.

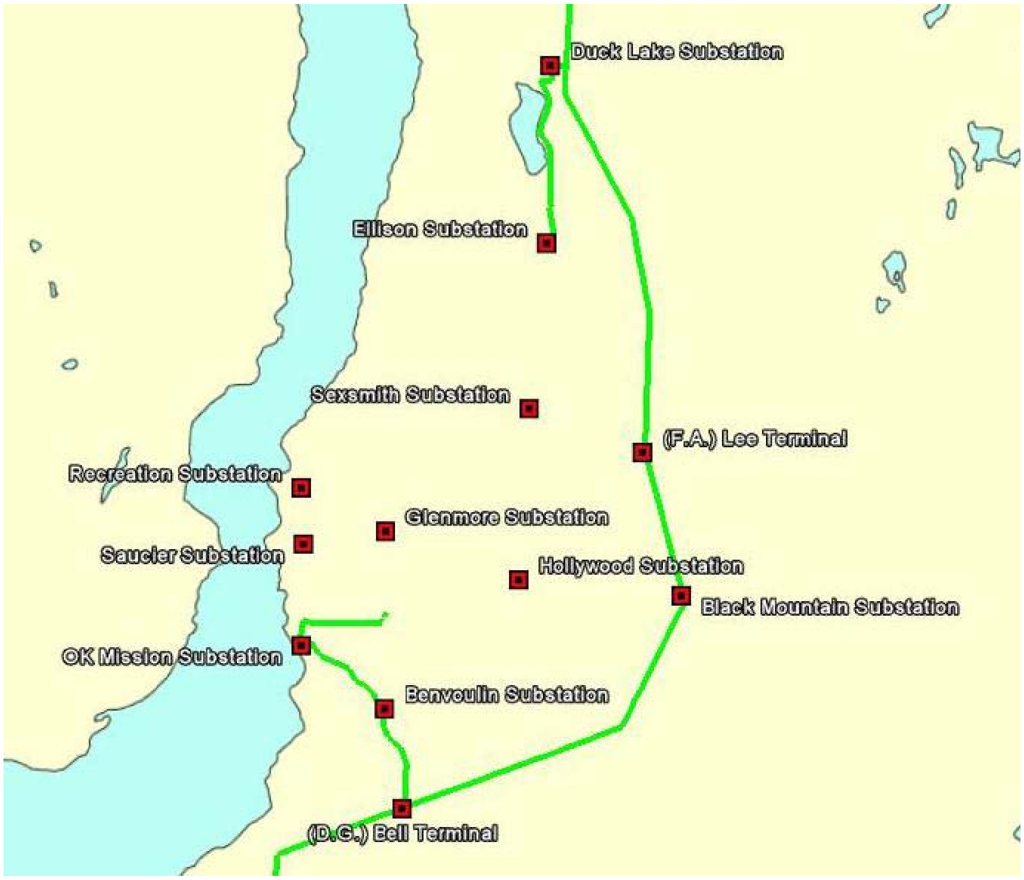
On the other hand, a physical break in the fibre, or severe degradation in the physical properties of the fibre due to environmental factors are risks that could sever the communications path. The implications are that all communications would be lost between the point of fibre failure and the distant end of the network.

This linear physical topology of the FortisBC fibre-optic network introduces a reasonable risk of prolonged communication outages at multiple substations. A minor event such as vandalism or a motor vehicle accident could sever the fibre-optic cable and the repair time could stretch to several days depending on the availability of field resources and material. If the failure was near the FortisBC System Control Centre, effectively all communications and control capabilities for the entire system would be unavailable.

4.2.3 KELOWNA GRID STABILITY

Kelowna has grown to become the largest city in the interior of British Columbia and the major economic hub for the region. Robust, reliable communications are important because the transmission network in the area is more interconnected (meshed) than in smaller municipalities. Consequently, any faults have a magnified effect on the stability of the power system. Presently, the Benvoulin, OK Mission, Recreation, Glenmore, Sexsmith, Hollywood and Saucier substations are not connected to the backbone of the FortisBC network and rely on low speed, equipment for all communications.

Figure 4.2.3 - Kelowna Substation Fibre Connections



Note: Kelowna area substations showing the current fibre-optic communications paths (green). OK Mission and Benvoulin substations are not connected to the backbone, but the fibre is routed adjacent to them.

4.2.4 TELECOMMUNICATIONS SPEED CONSTRAINTS

Many of the SCADA remote locations are constrained by low telecommunications bandwidth due to high capital costs or operations and maintenance costs to provide normal channels to these locations. Thus far, no operational impact has resulted from this constraint but as the operational responsibilities of the SCADA system evolve, the bandwidth and reliability requirements will increase and the existing limitations may become impediments. These systems should be replaced over time as opportunity and requirements dictate.

4.2.5 LOCATION AND FEEDER COVERAGE

The existing power quality electronic meters tend to be deployed at the generation and bulk transmission levels, with poor coverage at the distribution substation and feeder levels. Continued installation of remotely accessible electronic meters at lower levels will improve the proper characterization of load profiles (temperature and time) at feeder and transformer levels and will improve performance monitoring. Communications increases the timeliness and therefore usefulness of the information gathered by these meters.

4.2.6 MOBILE VOICE SHARED USE WITH SCADA

Because of the excellent coverage of the Very High Frequency (VHF) mobile system, FortisBC has used the mobile communications system to "piggyback" SCADA communications for 12 locations. The SCADA communication rarely occurs but when it does, it interferes with voice communications. Unfortunately, the communications conflicts occur in contingency conditions. For example during storm outages crews are active in the field at the same time the System Control Centre will be performing switches on the SCADA system. Efforts should be made over time to remove these SCADA transmissions from the VHF system to more reliable channels.

4.2.7 DIAL ACCESS TO TRANSMISSION SUBSTATIONS

AA Lambert and Princeton are transmission stations that have only dial-up telecommunications to the control rooms. This access could be blocked given a public emergency in the area.

4.2.7.1 Telecommunications Infrastructure Weak in Outlying Areas

Telecommunications facilities to Princeton, Coffee Creek, Crawford Bay, AA Lambert, Kaslo and Kraft are very limited, resulting in leased lines with operations and maintenance costs, poor operating reliability and no provision for growth.

4.3 Telecommunications, SCADA Protection and Control Projects

Table 4.3 below outlines the forecast expenditures for SCADA, Telecommunications and Protection and Control projects over the forecast period. The projects themselves are then further described below.

Table 4.3 - Telecommunications, SCADA Protection and Control Projects

		2012	2013	2014	2015	2016	2017-31
1	**Growth**	($000s)					
2	Kelowna 138 kV Loop Fibre and Multiplexer Installation	1,212	2,549	-	-	-	-
3	Kootenay Remedial Action Scheme-Install Redundant Backup System	-	-	-	1,166	3,162	-
4	Syncrophasor Data Collection Platform	-	-	-	-	623	-
5	Okanagan Remedial Action Scheme-Install Redundant Backup System	-	-	-	-	-	9,172
6	Princeton to Oliver Fibre Installation	-	-	-	-	-	14,349
7	**Total Telecom SCADA Protection and Control Growth**	**1,212**	**2,549**	**-**	**1,166**	**3,786**	**23,521**
8							
9	**Telecom SCADA Protection and Control Sustainment**						
10	Communication Upgrades	410	400	763	776	587	7,234
11	SCADA Systems Sustainment	707	733	784	811	843	14,863
12	Backbone Transport Technology Migration	-	-	410	6,652	-	-
13	Station Smart Device Upgrades	-	-	704	363	741	3,932
14	Telecommunications Ring Closure	-	-	-	-	-	4,265
15	**Total Telecom SCADA Protection and Control Sustainment**	**1,117**	**1,133**	**2,661**	**8,601**	**2,171**	**30,294**
16	**Total Telecom SCADA Protection and Control Projects**	**2,329**	**3,682**	**2,661**	**9,768**	**5,957**	**53,815**

4.3.1 GROWTH PROJECTS

4.3.1.1 Kelowna 138 kV Loop Fibre Installation

This project is a multiple-year effort to improve the capacity and reliability of the communications infrastructure in the Kelowna area and will lay the groundwork for future power system reliability improvements. The project includes the installation of multi-strand single-mode fibre cable which will supplement existing fibre leased under a long-term Indefeasible Right of Use (IRU) and existing FortisBC-owned fibre optic cabling. This will complete a physical fibre-optic ring to all Kelowna area substations. In addition, high speed digital multiplexers will be installed at these substations to take advantage of this new fibre and facilitate high speed, reliable communications in the area, including the future ability to fully mesh substation protection systems.

FortisBC has recently reached a settlement that secures reasonably priced, long term access to fibre in the area; therefore, there are no additional capital costs to this project for use of this fibre. The proposed build would allow FortisBC to fully leverage this existing fibre that FortisBC now has access to by completing gaps in the third party's network, and thus completing a physical fibre loop to all Kelowna-area substations. This enhances the reliability of communications in the area and makes possible the delivery of robust services to all locations. Without this additional fibre construction, FortisBC will be unable to take full advantage of the leased fibre and three major distribution substations in central Kelowna will not be able to be connected to the fibre network.

Options Analysis

The existing 900 MHz wireless communications system in Kelowna has reached end-of-life and requires replacement in order to maintain existing service levels. On that basis, the "Do Nothing" option is not applicable as the system will eventually fail and repair parts are no longer available. The current system provides primary communications to Sexsmith, Hollywood, Glenmore, Recreation, Saucier, OK Mission and Benvoulin Substations.

FortisBC examined several different alternatives to replace this existing point-to-multipoint wireless system before determining that the construction of a fibre-based communications network best served the long term customer needs. These included the following options:

a) Replace the existing Kelowna wireless system with similar equipment of modern vintage;

b) Replace the existing Kelowna wireless system with power-line carrier equipment;

c) Replace the existing Kelowna wireless system with point-to-point wireless communications;

d) Replace the existing Kelowna wireless system with leased communications services from a telecommunication service provider;

e) Replace existing wireless communication systems with fibre-optic cable and multiplexing equipment without path redundancy; or

f) Replace existing wireless communication systems with path redundant fibre-optic cable and multiplexing equipment.

Table 4.3.1.1 below provides a comparison of the six options considered.

Table 4.3.1.1 - Kelowna 138 kV Loop Fibre Installation - Option Cost Summary

Option	Capital Cost	NPV Lease Cost[1]	Total Cost	SCADA	Tele-protection	Other Operational Traffic[2]	Highly Reliable[3]	Future Capacity[4]	No Reliance on Third Party	Simplified Maintenance[5]	Fully Redundant
A	$1,816,000	$675,467	$2,491,467	X		X					
B	$5,449,000	$675,467	$6,124,467	X	X		X			X	
C	$6,203,000	$675,467	$6,878,467	X	X	X	X				
D	$631,000	$1,688,668	$2,319,668	X							
E	$3,215,000	$0	$3,215,000	X	X	X	X	X	X	X	
F	$3,761,000	$0	$3,761,000	X	X	X	X	X	X	X	X

[1] NPV Lease Cost uses simplified method to calculate the present value of recurring monthly costs over 30 years (no inflation of lease costs)

[2] Other operational traffic includes operational WAN, phones or corporate WAN services available to substations

[3] A system is considered highly reliable if its availability is sufficient to assume outage length will not be increased by its outages (>99.95%)

[4] Future capacity considers the ability to accommodate unknown future applications on the infrastructure (assuming high bandwidth)

[5] A system is considered to have simplified maintenance if all maintainable facilities are located within FortisBC assets (substations)

The analysis shows that with the exception of the power line carrier and wireless point-to-point options, all other alternatives were of similar cost (within 15 percent) when considered over a longer time frame.

The redundant fibre option (Option F) is the proposed solution as it provides by far the most functionality, flexibility and performance. Furthermore, it is also the most "future-proof" system since once the fibre cable infrastructure is constructed; it has a long life (25 years or more) when compared to other technologies. Consequently, since communications technologies change rapidly, once the physical infrastructure is in place costs associated with these future upgrades and migrations are greatly reduced. This major benefit of fibre infrastructure has not been captured in this financial analysis, but should not be overlooked as a benefit when comparing the options from a qualitative perspective.

Description of Recommended Option (F)

The following are the fibre route details for the proposed fibre-optic ring:

- 66 km total fibre ring;
- 47.25 km existing on fibre owned or leased via IRU by FortisBC;
- 4.1 km new fibre built on FortisBC distribution structures;
- 1 km new fibre in FortisBC underground duct; and
- 8.6 km new fibre on FortisBC transmission structures.

Figure 4.3.1.1 - Existing and Proposed Kelowna Area Fibre Network

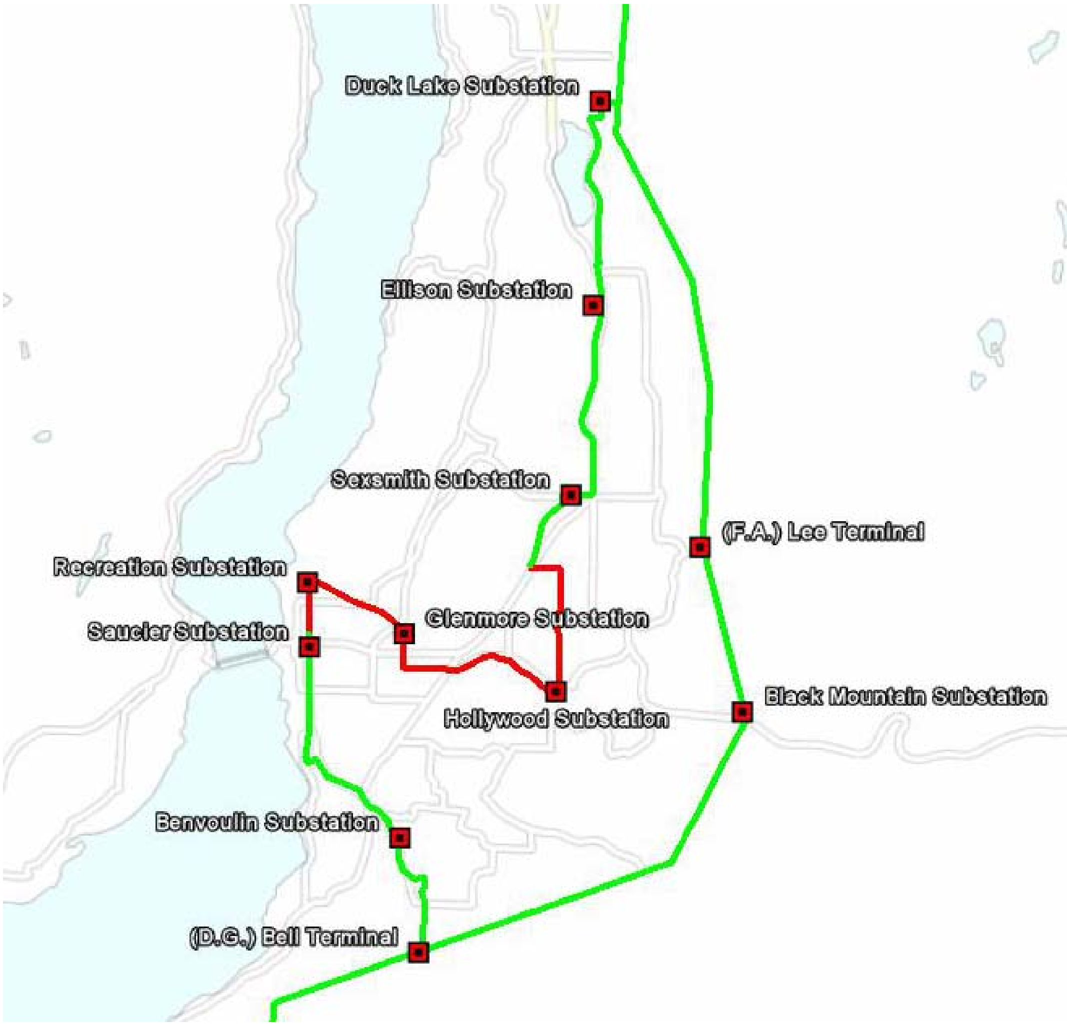


Figure 4.3.1.1 above depicts the routing of the existing and proposed fibre optic network in the Kelowna area. Existing fibre that FortisBC either owns or has access to via an IRU is shown in green. The red lines indicate the proposed construction required to complete the fibre loop and provide connectivity to the Recreation, Glenmore and Hollywood substations. At peak times, these three major substations combined supply approximately 125 MW of load in the most densely populated portion of Kelowna.

The complete project will improve the safety and reliability for this growing urban area and provide high-bandwidth communications for current-day operations as well as support future initiatives relating to transmission system protection, Smart Grid, Advanced Metering Infrastructure (AMI) or distribution network automation. Furthermore, it will reduce operating costs by eliminating the dependence on third-party leased services both for corporate and operational communications. This fibre will replace existing wireless communication equipment which has reached the end of service life and is becoming increasingly unreliable. Finally, as any new cable will be under-strung on existing FortisBC transmission and distribution structures, no new rights of way or line construction is required. If approved, FortisBC would expect to complete the fibre portion of the project in 2012 and install the communications multiplexers in 2013.

Future Enhancements

The reliability of the Kelowna-area transmission system could be further enhanced in the future by operating the transmission network fully meshed as proposed for the 2014-16 timeframe. This is a separate project that will directly address transmission system protection and operational limitations and improve customer reliability through a reduction primarily in the frequency of wide-scale transmission outages.

4.3.1.2 Kootenay Remedial Action Scheme - Install Redundant Backup System

FortisBC, Columbia Power Corporation, BC Hydro and Teck have jointly and independently conducted planning studies and contingency analyses for the Kootenay 230 kV system. All of the parties identified specific contingencies and required the installation of fast-acting Special Protection Systems that either shed load or generation to maintain the integrity of the remaining system. Because of the abundance of generation facilities in the region, the emphasis of the scheme was to ensure transmission facilities are not overloaded with excess generation capacity.

The RAS system was installed several years ago and at the time it was planned to add redundancy in the future. Presently, the communications channel is the only redundant portion of the system. The project scope would be as follows:

- Install redundant Protection Logic Processors at each RAS location;
- Install redundant Protection, Automation and Control System at each RAS location;
- Rewiring of all RAS signally lines to ensure redundancy to end equipment;
- Upgrades of battery systems where needed; and
- Installation of redundant power supply or DC-DC converter.

The project is estimated cost of $1.17 million in 2015 and $3.16 million in 2016.

4.3.1.3 Syncrophasor Data Collection Platform

The project will improve FortisBC's System Control Centre's situational awareness by collecting and presenting useful synchrophasor information to the power system dispatchers. Presently, FortisBC has a large number of SEL relays that calculate this information in real time, but as yet has no method to collect and use this data to enhance the reliability of the power system. At the conclusion of the project, system operators will be able to monitor phase differences between sites and identify any impending problems more effectively.

The initiative supports the 2007 BC Energy Plan in two ways, by:

- Ensuring that British Columbia's transmission technology and infrastructure remains at the leading edge and has the capacity to deliver power efficiently and reliably to meet growing demand.
- Participating in the BC Energy Plan Real Time Phasor initiative, a local adaptation of the North American Synchrophasor Initiative (NASPI).

The project consists of:

- Installing a central data collection platform to collect synchrophasor information from existing relays;
- Installing software to present the information to FortisBC's dispatchers; and
- Communicating real-time synchrophasor information to BC Hydro and WECC as required.

The project is scheduled to take place in 2016 with an expected cost of $0.62 million.

4.3.1.4 Okanagan Remedial Action Scheme - Install Redundant Backup System

FortisBC and BC Hydro have jointly and independently conducted planning studies and contingency analyses for the Okanagan transmission system. Both parties have identified specific contingencies that will require the installation of fast-acting Special Protection Systems that either shed load/generation or open transmission lines to maintain the integrity of the remaining system.

The RAS system was installed several years ago and at the time it was planned to add redundancy in the future. Presently, the communications channel is the only redundant portion of the system. The project scope would be as follows:

- Install redundant Protection Logic Processors at each RAS location;
- Install redundant Protection, Automation and Control System at each RAS location;
- Rewiring of all RAS signally lines to ensure redundancy to end equipment;
- Upgrades of battery systems where needed; and
- Installation of redundant power supply or DC-DC converter.

The project is estimated to cost $3.07 million in 2019 and $6.10 million in 2020.

4.3.1.5 Princeton to Oliver Fibre Installation

This project would install multi-strand single mode fibre between Oliver and Princeton, facilitating robust, reliable high speed communication to the Keremeos, Hedley and Princeton substations.

Presently, Princeton and Keremeos each have a leased circuit and a cellular modem and Hedley has a leased circuit and a satellite modem. These solutions are low speed and inherently unreliable, putting constraints on the monitoring and control capabilities at the stations. It would be difficult to support any newer applications such as distribution automation or advance metering infrastructure and impossible to support teleprotection without infrastructure upgrades. In addition, the recurring monthly lease costs for the circuits make them operationally expensive in the long term.

The build would most likely occur along the 138 kV 43 Line transmission line and is estimated for the years 2021-2022. This project is estimated to cost approximately $14.35 million.

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 North Warfield Substation** - 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

project due to expectation that they would be taken out of service within a few years. The stations at Kaleden, OK Falls and Ymir are no longer slated to be removed from service in the immediate future, therefore these automation upgrades will be completed at these stations in 2014/2015.

- **Wireless Upgrade** - FortisBC has licensed and unlicensed wireless systems in the Okanagan designed to provide services to facilities for voice/data and SCADA applications. These systems are near or beyond the end of their useful service life and will need to be upgraded. This is estimated for the 2016 - 2017 timeline.

Table 4.3.2.1 - Communication Upgrades

Year	2012	2013	2014	2015	2016	2017-31
	($000s)					
Cost	410	400	763	776	587	7,234

4.3.2.2 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.

Table 4.3.2.2 - SCADA Systems Sustainment

Year	2012	2013	2014	2015	2016	2017-31
	($000s)					
Cost	707	733	784	811	843	14,863

4.3.2.3 Backbone Transport Technology Migration

The FortisBC network is presently using TDM technology (SONET) at the core of its network, with digital channel banks at the edges to provision circuits for each application. This technology is mature and robust, and a great fit for the communications needs of utilities.

Unfortunately, the relatively small size of the utility communications market in comparison to the traditional telecommunications market means that utilities will be forced to migrate their technologies in step (though lagging behind) with the telecommunication companies. The telecom industry began migrating to a packet based switching technology several years ago, and many utilities have plans to do the same in the near future. As the number of TDM installations decreases, so will the economies of scale and the price of new equipment and parts will begin to rise.

For this reason, it is inevitable that at some point in the future, the vendor supplying the underlying SONET/TDM multiplexers in the network will announce plans to discontinue the product and its support and move on to other technologies.

Furthermore, many new applications are packet based and most legacy applications are also migrating in that direction, therefore the risks of migration are being rapidly removed. FortisBC will be looking more closely at migrating important infrastructure in 2012 and will investigate strategies and timelines based on the vendor options.

This project is estimated to cost $0.41 million in 2014 and $6.65 million in 2015.

4.3.2.4 Station Smart Device Upgrades

FortisBC has a large number of electromechanical and electronic relays that do not meet current monitoring and protection standards. Replacement of these relays will increase system reliability and efficiency by providing real time telemetry, recording fault data and reducing the need for complex protection schemes.

This recurring multi-year project will update these devices and integrate them into the telecommunications network. The project has been scheduled to run from 2014 to 2023 and during the course of the program stations requiring upgrades will be identified based on several factors including reliability, complexity, probability of failure and benefit to system operation. The goal will be to complete one station upgrade per year over the course of the program.

Deferring this project will increase the likelihood and duration of outages by making it more difficult to remotely troubleshoot and diagnose system instability problems and abnormal operating conditions.

Three stations have been selected for upgrades in 2014-2016 and additional stations will be identified in future Capital Expenditure Plans:

- **Pine Street Transformer Protection** - The existing transformer (T2) over-current high voltage relay is an older style relay that does not have enough inputs and outputs. This prevents the protection and control system from implementing an automatic reclose scheme to improve reliability in the event of a transformer fault. Updating the relay to our current standard would also give reliable operating data on the transformer.

- **OK Mission High Voltage Transformer Protection for T1 and T2 -** This project involves the replacement of the existing over current relays on OK Mission T1 and T2 transformers. The existing relays do not have enough inputs and outputs to meet present day requirements, consequently the number of trip signals that can be seen by the relay is limited. The relay cannot provide trip coordination or protection telemetry resulting in maintenance coordination issues between T1 and T2 High Voltage (HV) protection. The new relay will incorporate non-electrical trips that are presently routed through another tripping relay. The new configuration will increase the reliability and effectiveness of the high voltage protection system for T1and T2 transformers. Upgrading these relays will have the added benefit of increasing the telemetry available for protection planning. The relay replacement will bring T1 and T2 transformers up to FortisBC's protection standards, thereby reducing operational and maintenance co-ordination issues.
- **Hedley 43A Line Protection -** 43A Line is a 138 kV transmission line serving a primary voltage customer. The currently installed electromechanical relays are obsolete and do not have the ability to record fault data or transmit telemetry. This project will remove the existing relays from the line terminating at Mascot Mines and replace them with redundant PY and SY SEL-311C relays. In addition, to facilitate the protection operation a, three-phase VT and a second CT for the circuit breaker will be added. The project will take place concurrently with the replacement of the circuit breaker that is occurring under a different project. The new configuration will increase the reliability and effectiveness of the high voltage protection for 43A Line.

Table 4.3.2.4 - Station Smart Device Upgrades

Year	2014	2015	2016	2017-31
	($000s)			
Cost	704	363	741	3,932

4.3.2.5 Telecommunications Ring Closure

The linear physical topology of the FortisBC fibre-optic network introduces a reasonable risk of prolonged communication outages at multiple substations. A minor event such as vandalism or a motor vehicle accident could sever the fibre-optic cable and the repair time could stretch to several days depending on the availability of field resources and material.

FortisBC will work to complete a redundant communication path between the two service areas, most likely using microwave radio between Corra Linn Dam and BC Hydro's Vernon Terminal. This could be achieved by deploying FortisBC owned equipment on existing BC Hydro towers at Slocan Ridge, Scaia and Silver Star, or by leasing circuits. Alternatively, a link into the Kelowna area could be achieved using the existing FortisBC site at Blue Grouse Mountain, a new site at Big White (Summit) and the BC Hydro owned towers at Scaia and Slocan Ridge.

Figure 4.3.2.5 - Corra Linn to Vernon Terminal Link

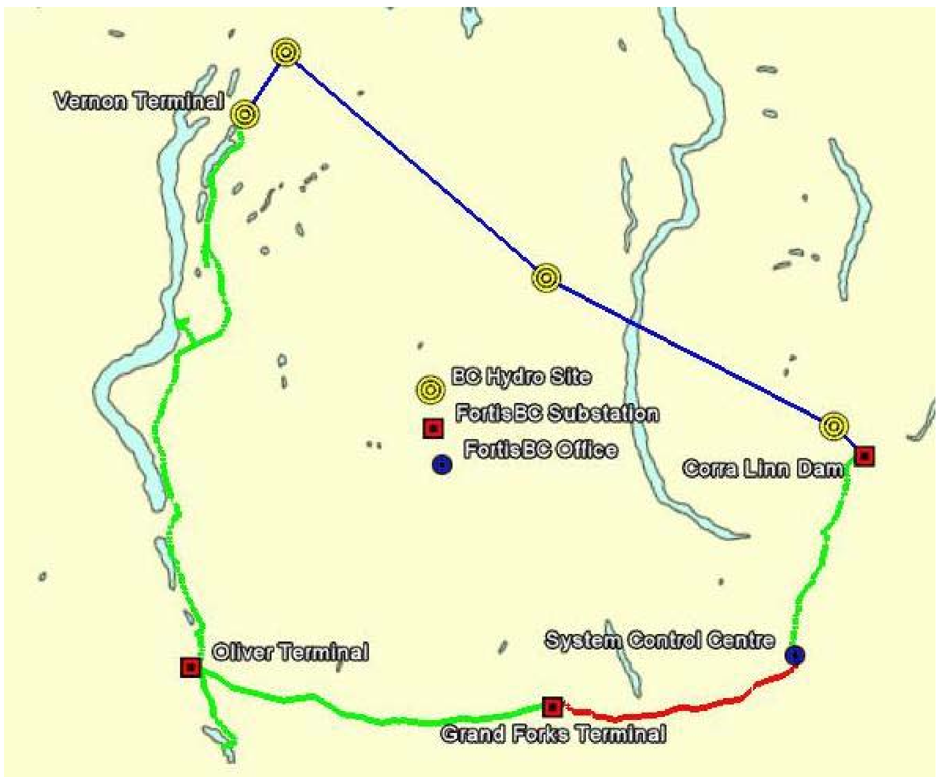


Figure shows the Corra Linn to Vernon Terminal link (blue), closing the FortisBC communications network, assuming the fibre build between Grand Forks and Warfield (red) has occurred. Existing fibre is shown in green.

The completion of this project will increase the efficiency of operations by reducing the probability of communications outages on the FortisBC system. This could also facilitate new control schemes that would further reduce operating costs and increase reliability. In addition, the redundancy will ensure FortisBC is capable of meeting any future NERC reliability standards.

The project is scheduled to occur in the 2017-2018 timeframe with an expected cost of $4.27 million.

5. GENERAL PLANT

General plant consists of vehicles, metering, information systems, telecommunications, buildings, furniture and fixtures, tools and equipment. These areas provide support services, facilities and technologies that enable the effective and efficient delivery of the electrical services that FortisBC customers expect of their electric utility.

Budgets requested in each of the General Plant subsections are based on the requirements generated by 2012 Long Term Capital Plan projects over the planning horizon. Specifically, the facilities, vehicles and technologies included in General Plant are determined by reviewing the overall 2012 Long Term Capital Plan and planning the required support.

It should be noted that all expenditures related to the operations of the FortisBC Supervisory Control and Data Acquisition (SCADA) system and its associated equipment are now captured within the Telecom/SCADA/Protection and Control section of the 2012 Long Term Capital Plan (Section 4).

Previously, only expenditures for field equipment such as substation devices and communications systems were included in the Telecom/SCADA/Protection and Control category. Expenditures related to the SCADA system itself (such as computer hardware and software), were previously contained in the General Plant budget category.

Expenditures related to the operation of the System Control Centre, such as facilities, furniture and information technology equipment not associated with the SCADA system, are still included within the General Plant section.

This change has been made to improve transparency of costs related to the operations of the FortisBC SCADA system.

Table 5.0 below shows the estimated expenditures in General Plant.

Table 5.0 - General Plant Expenditures

	General Plant	2012	2013	2014	2015	2016	2017-31
		($000s)					
1	Kootenay Long Term Facilities Strategy	6,020	10,477	-	-	-	-
2	Trail Office Lease Purchase		10,000	-	-	-	-
3	Okanagan Long Term Solution	69	75	3,984	-	-	-
4	Central Warehousing	1,755	-	-	-	-	-
5	Advanced Metering Infrastructure	4,501	27,931	6,099	-	-	-
6	**Information Systems**						
7	Infrastructure Sustainment	1,111	1,118	1,207	1,244	1,355	23,967
8	Desktop Infrastructure Sustainment	1,115	1,122	1,239	1,277	1,321	23,368
9	Application Enhancements	1,235	1,242	1,296	1,336	1,382	24,447
10	Application Sustainment	1,179	1,210	1,276	1,341	1,441	40,220
11	PowerSense DSM Reporting Software	1,032	-	131	135	140	1,205
12	Vehicles	2,541	2,574	2,699	2,796	2,906	51,411
13	Metering Changes	403	406	212	222	234	8,179
14	Telecommunications	121	183	191	196	203	3,595
15	Buildings	1,362	883	601	278	287	7,273
18	Furniture and Fixtures	121	122	508	105	108	2,071
19	Tools and Equipment	528	457	477	491	508	8,236
20	**Total General Plant**	**23,093**	**57,800**	**19,920**	**9,423**	**9,885**	**193,974**

5.1 Kootenay Long Term Facilities Strategy

This project is prompted by the aging and inadequate sizing of current facilities at FortisBC's South Slocan, Castlegar and System Control Centre. A long term space strategy for these sites is being developed to deal with the following key drivers:

- Condition assessment of the South Slocan facilities has identified numerous safety, environmental, structural issues that need to be addressed;
- The System Control Centre site is currently undersized and using a portable trailer. NERC and BC Mandatory Reliability Standards are under review and it is believed a number of site upgrades will be necessary;
- The Castlegar operations site is inadequately sized and the current property entrance/exit to the road is difficult and unsafe;
- Opportunity for synergies in staffing, crew dispatching and shop requirements;

- Opportunity to reduce energy usage - South Slocan administrative were not designed for their current use and due to age of structures have no energy efficiencies built into their design; and

The project will include acquiring land and building a new Operations Centre and modifications/demolitions to existing facilities that provides:

- Efficiently planned buildings that maximizes square footage, integrates employees and meets FortisBC's current and future needs;
- Prudently eliminates risk around critical response and aged facilities with safety and environmental issues;
- Commits to a community presence in the area the company is serving for the life of the business; and
- Provides energy efficient buildings that meets FortisBC and BC Government's mandates for energy and the environment.

This project is estimated to cost $6.02 million in 2012 and $10.50 million in 2013.

5.2 Trail Office Lease Purchase

The Trail Office lease is a 30 year lease that commenced September 28, 1993 and was approved by Commission Orders G-41-93 and G-41-94. Under the terms of the lease, the Company has the opportunity to purchase the building on September 30, 2013. The total price of the purchase is approximately $10 million. The avoided lease costs would be $1.974 million annually until September 30, 2023. The lease contract does not allow termination, other than by way of the purchase (2012 - 2013 Revenue Requirements, Tab 6, section 6.2). All costs associated with operating and maintaining the Trail office are paid for by the Company. Therefore, the decision of continuing to lease vs. exercising the purchase option is isolated to a lease vs. purchase financial decision. Purchasing the building and including the cost in rate base is expected to be cost neutral because it eliminates the annual lease costs.

5.3 Okanagan Long Term Solution

Currently FortisBC occupies two operations sites in Kelowna.

- The Benvoulin Operations Center is an owned facility/yard combination of office, district warehouse and yard facilities housing line services crews, design, engineering, administrative staff.
- The Enterprise Road site is a leased combination of office and yard housing Kelowna area/large capital warehouse, construction and maintenance crews, engineering, planning and administrative staff. The lease for this property expires in December 2012.

The intent is to consolidate these sites at one location, including any FortisBC gas division requirements where applicable. The key drivers for this are:

- Opportunity for synergies in staffing, crew requirements, material storage;
- Opportunity for productivity improvements due to travel to another site for material pick-up in heavy traffic areas;
- Opportunity to review warehousing requirements, as further discussed in Section 5.4 below;
- Current lease costs in Kelowna are expensive, opportunity to reduce costs; and
- Opportunity to improve safety regarding access/egress to the Benvoulin site

Development funding was approved through the 2011 Capital Expenditure Plan to review existing Company-owned sites and to develop alternative building and site plans. Further recommendations will be made once this review is complete.

5.4 Central Warehousing

This project will fund the centralizing of warehousing for FortisBC to the Warfield site. Three main warehouses will consolidate into the one, including the Enterprise site in Kelowna as the lease at the Enterprise site expires in December 2012. District stores would only have an inventory of emergency materials to deal with outages, as well as staging for kitted materials. The kitted materials would be for jobs that have been designed and planned in advance.

To accommodate the facility requirements of central warehousing the Warfield warehousing space will be increased to an estimated 12,000 square feet. The project costs include the addition of the new warehouse space and the appropriate racking, as well as relocation of the business groups from the Enterprise facility.

By centralizing warehousing to Warfield the additional space leased at the Enterprise site will not need to be replaced when the lease expires. This will reduce costs to the organization by $600,000 annually. The project is estimated to cost $1.80 million in 2012.

5.5 Advanced Metering Infrastructure

FortisBC plans to execute its Advanced Metering Infrastructure project, subject to Commission approval of a CPCN application to be submitted in 2011. The scope of the AMI project is expected to include:

- Meters and Modules - As part of its AMI program, FortisBC intends to install AMI-enabled meters for all of its direct customers over a two year period beginning in 2013. These meters will be capable of two-way communications and providing hourly interval data.
- Communications Infrastructure - The AMI communications infrastructure is expected to collect and transfer readings, alarms and other meter data from the metering end points into the system's Head End System (HES). It will also be responsible for providing communications to other downstream devices such as in-home displays or other smart grid devices.
- IT Infrastructure - The AMI System implementation will include a Meter Data Management System (MDMS) that will be the central repository for all meter related data. The MDMS will integrate with the AMI Head End System which is the application that manages the AMI network. The Head End System will manage the communications, operations, and diagnostic monitoring of the electric meters and field devices.

The integration of FortisBC's core systems such as CIS and Geographic Information System (GIS) will also be an integral part of the AMI implementation.

The following are FortisBC's key objectives with respect to the implementation of AMI:

- Improve operational efficiencies by reducing operating costs;
- Improve customer service by increasing the accuracy and timeless of their bills and providing better data to resolve customer concerns;
- Support conservation and efficiency objectives by enabling conservation rates and providing customers with more information on their consumption;

- Protect revenue by identifying and resolving non-technical system losses; and
- Support customer in-home automation by providing usage information and price signals into the customer's home.

The project schedule is expected to see deployment of the communications component beginning in late 2012, with meter replacements beginning in early 2013. The project is schedules for completion at the end of 2014. The project is forecast to have a capital cost of approximately $47.18 million with expenditures of $4.50 million in 2012, $27.93 million in 2013 and $6.10 million in 2014. The project is expected to be approximately cost neutral as a result of the operating savings.

5.6 Information Systems Projects

The information systems component focuses on the next two years, 2012 and 2013. Technology changes too rapidly to precisely plan requirements beyond that timeframe. Information systems planning and estimates beyond the two-year horizon are based primarily on historical spending.

The general long term strategy for Information Systems will continue to concentrate on leveraging the benefits of existing systems and delivering information from those systems in a single view based on individual needs. This strategy reduces access and training time, as all information relevant to an individual is accessed through a familiar web style interface. One of the main technologies being used to facilitate this strategy is Service Oriented Architecture (SOA), which allows for simpler and more versatile method of connecting systems without creating older style hard coded interfaces. This greatly simplifies upgrade paths for applications as well.

The Customer Information System (CIS) will be re-evaluated within the next 3 to 4 years. The CIS is a core utility system which provides billing and customer information. The current system was originally installed in 2000. The re-evaluation will be to ensure the system can continue to support customer and Company requirements from a billing and information perspective. The review will also verify supportability and interoperability of the software into the future. Periodic investments and enhancements to the system have kept it viable since 2000 when it was implemented. However, a review in the proposed time frame is prudent, as the life expectancy of billing systems is generally 15 to 20 years. Should the evaluation determine that a replacement of the system be required a CPCN will be developed identifying a recommended option. The timing of the review will also afford the Company sufficient time to implement a new system should it be required.

The primary objective for all areas of information systems for the 2012 to 2014 timeframe will be to support system requirements of the Advanced Metering Infrastructure (AMI) project. AMI may require changes, additions and interfaces with the enterprise solution (SAP), customer information system (CIS), and the automated mapping and facility management system (AM/FM). AMI will require infrastructure support and changes to incorporate the new communications requirements into the existing network. It will also require infrastructure support to ensure adequate platform capabilities and capacities are available for the incremental systems and data that will come with the project. Internal resources will be used where possible on the project to leverage existing experience with FortisBC systems and infrastructure. This will help ensure a smooth project execution. Costs associated with Information System resources will be included in the Certificate of Public Convenience and Necessity (CPCN) for the Advanced Metering Infrastructure project.

Outside AMI initiatives over the next two years will concentrate on application enhancements and integrations in support of the asset management strategy. There will also be a focus on a business intelligence strategy to help retain knowledge and experience that could be lost through retirements of long term employees. The business intelligence strategy will also provide structured data to support planning and forecasting, as well as making information more accessible for all decision making.

As always initiatives to enhance customer service and support will also be a priority. This includes the implementation of a tracking and reporting tool for the expanded DSM program, dispatch and work management improvements, customer self service enhancements including internet site enhancements, outage management implementation, distribution design enhancements and automation.

From an infrastructure standpoint FortisBC will continue to leverage virtualization technology, which maximizes the use of hardware by allowing several virtual machines to be hosted by one physical machine. This helps control both desktop and server costs. The Company will continue to focus on more mobilization technology to deliver better and faster information to the mobile user in support of safety and customer service.

Capital spending for Information Systems is shown below in Table 5.6.

Table 5.6 - Information Systems

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	6,655	4,543	4,768	4,309	4,682	5,671	4,692	5,150	5,334	5,638	113,208

5.6.1 INFRASTRUCTURE SUSTAINMENT

The infrastructure sustainment project includes replacing out-dated hardware and software (operating systems and related server software) in the primary and backup data centres and supporting infrastructure (switches and routers that tie the Wide Area Network together). There is approximately $3.2 million worth of hardware and software associated with the FortisBC's Information System infrastructure. The life expectancy of the hardware infrastructure components is a maximum of five years, based on industry standards and manufacturers' support. Operating systems are typically upgraded every two years to maintain vendor support. The budget is developed based on the replacement of the oldest equipment (five year maximum life expectancy), failed equipment and minimum software upgrades to maintain manufacturer support. This strategy of asset management avoids the complete replacement of all equipment every five years at one time, as well as the work disruption that would result.

Equipment and software designated for upgrade typically include servers at end of life, disk drives that have passed maximum life expectancy (over 20 terabytes of disk space in each data centre), networking infrastructure replacements (failed switches, routers and hubs) and operating system and database upgrades.

5.6.2 DESKTOP INFRASTRUCTURE SUSTAINMENT

Desktop Infrastructure Sustainment includes Microsoft Windows operating system, Microsoft Office Suite and other job specific hardware and software upgrades for FortisBC's personal computer (PC) environment. It is a phased approach to keeping approximately 670 PCs current and supportable, rather than replacing all PC equipment and software every five years. The life expectancy of the desktop hardware is a maximum of five years based on industry standards and manufacturers' support. The phased replacement strategy avoids the resourcing and disruption issues that occur with complete replacement of all personal computer equipment every five years. The total value of FortisBC's desktop hardware and related peripherals is approximately $3 million. The Desktop Infrastructure Sustainment budget is developed based on the replacement of the oldest (maximum five year life expectancy) and failed equipment.

This program also includes the cost necessary to replace fax machines, telephones and photocopiers/printers to maintain reliability and compatibility with industry standards. This staged approach is based on standard lifecycles.

A management tool is used to track the age of all technology assets at FortisBC to ensure they are replaced in a timely manner and to realize maximum life expectancy without jeopardizing productivity.

5.6.3 APPLICATION ENHANCEMENTS

This project will fund any application enhancements that are required during the year. Enhancements to existing systems are initiated when a business requirement or opportunity arises that requires a long term solution. These enhancements do not generally include additional licenses or hardware, but do include configuration, integration and process modification to take advantage of a particular application's inherent functionality.

Examples of some of the expected enhancements and their drivers:

The reporting, analysis, and interpretation of business data is of central importance to a company in optimizing decision making. Business Intelligence (BI), SAP NetWeaver provides data warehousing, a business intelligence platform, and a suite of business intelligence tools that deliver this capability. Relevant business information from productive SAP applications and all external data sources are integrated, transformed, and consolidated in BI with the tool set provided. BI provides flexible reporting, analysis, and planning tools to support evaluation and interpretation of data, as well as facilitating its distribution. Businesses are able to make well-founded decisions, predict future possibilities and determine target-orientated activities on the basis of this analysis. Investments will be made in 2012 and 2013 to develop BI in support of the data requirements of the organization for reporting in customer service, operations, finance, human resources and geographic information system data.

Additions and enhancements will be made to customer systems, such as the internet web site, to enhance customer self-service and information availability. Electronic billing options and capabilities will also be enhanced to broaden customer options.

Enhancements will be made to improve and automate interfaces between the AM/FM mapping system, CIS, and the Survalent Worldview control system. These interfaces allow for a real time view of the electrical network on a scaled map of the electrical system, visibility of vehicle locations in relation to customers and improved restoration information by relating customers to the electrical network.

Other enhancements will be undertaken on a priority, benefit and resource availability basis. These enhancements can be driven by legislative, regulatory or business processes.

5.6.4 APPLICATION SUSTAINMENT

This project will fund the annual sustainment requirements for all FortisBC applications including CIS, SAP, AM/FM and all other applications used at FortisBC. Annual upgrades maintain support and avoid potential productivity or reliability issues, as well as making new functionality and features available that the vendors have developed through continued investment in their products.

5.6.5 POWERSENSE DSM REPORTING SOFTWARE

This project is to implement software to be used by the PowerSense department to track, calculate savings and report on DSM projects from inception to completion. Due to the expanding and increasing number of programs and DSM projects, this software is required to capture the appropriate customer transaction information, improve internal workflow processes to provide better customer service, advance monitoring and evaluation, and ensure optimal expenditures. This software will track interactions with each customer from project initiation to completion and provide robust reporting capabilities. FortisBC does not currently have software that is capable of meeting the requirements of the expanded DSM program. The solution will be selected based on its ability to meet requirements at the most reasonable cost, while aligning with FortisBC application standards. The DSM Tracking and Reporting Software project is the only sizeable software implementation project, outside of AMI, that is planned in the 2012-13 timeframe.

Table 5.6 - Information Systems Projects

	Information Systems	**2012**	**2013**	**2014**	**2015**	**2016**	**2017-31**
		($000s)					
1	Infrastructure Sustainment	1,111	1,118	1,207	1,244	1,355	23,967
2	Desktop Infrastructure Sustainment	1,115	1,122	1,239	1,277	1,321	23,368
3	Application Enhancements	1,235	1,242	1,296	1,336	1,382	24,447
4	Application Sustainment	1,179	1,210	1,276	1,341	1,441	40,220
5	PowerSense DSM Reporting Software	1,032	-	131	135	140	1,205
6	**Information Systems Total**	**5,672**	**4,692**	**5,150**	**5,334**	**5,638**	**113,208**

5.7 Vehicles

FortisBC's Fleet department supports the 2012 Long Term Capital Plan by meeting vehicle requirements based on this long-term plan. Fleet also bases planning on the Company's objectives to enhance safety, reliability, customer service, and reduce costs and the Company's environmental footprint.

FortisBC currently has 350 units in its fleet. 287 units are owned and 63 units are leased. In 2012 and 2013, FortisBC plans on replacing 23 and 35 units respectively. FortisBC's equipment replacement guidelines are listed in the table below.

Table 5.7 (a) - Replacement Criteria Trigger

Description	Trigger
Passenger Vehicles	160,000 km (Gasoline) 200,000 km (Diesel)
3/4 Tons and Smaller	160,000 km (Gasoline) 200,000 km (Diesel)
Service Vehicles (3/4 and One Tons) 2 and 4 Wheel Drive	160,000 km (Gasoline) 200,000 km (Diesel)
Line Trucks (Digger or Aerial) 2 and 4 Wheel Drive	10 years / 200,000 km
Trailers	20 years
Specialty and Small Horsepower (Forklifts, Snowmobiles, ATVs)	Individual Review

In making the actual replacement decision many key issues are considered including suitability to meet current and future business requirements, ability to maintain adequate safety, age, condition, and compliance with regulations. A replacement decision is done on a unit by unit basis. All units to be replaced have either exceeded their planned life cycle, or, are becoming a safety, reliability or compliance risk. Electric utilities rely on the availability of specialized, reliable, safe, and efficient vehicles. Deferring these planned expenditures has the possibility of negatively affecting employee (and public safety), as well as potentially resulting in increased operating expenses as a result of repair costs and equipment shortages.

Vehicle expenditures include the replacement and/or addition of heavy fleet vehicles, service vehicles, passenger/light duty vehicles, and specialty equipment and off-road vehicles necessary for FortisBC to conduct its operation in a safe and cost effective manner.

Fleet represents approximately 78 percent of FortisBC's greenhouse gas emissions. The Company currently has seven hybrid low emission passenger vehicles and a hybrid low emission service truck. Also, in concert with FortisBC Energy Inc., the Company has begun exploring opportunities for using natural gas vehicles. The Company will continue to monitor and evaluate the progress of all new green vehicle technologies as part of its future purchases.

Table 5.7 (b) - Vehicles

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	4,387	1,277	1,947	1,225	2,738	2,541	2,574	2,699	2,796	2,906	51,411

5.8 Metering Changes

This project involves the purchase of new metering infrastructure driven by customer growth, as well as replacement for metering equipment that fails during the metering compliance or the meter re-test program. Metering infrastructure includes meters, current transformers, potential transformers and ancillary equipment.

Table 5.8 - Metering Changes

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	481	115	136	181	472	403	406	212	222	234	8,179

5.9 Telecommunications

The telecommunications capital budget is used to purchase new or replacement communications equipment. This equipment includes landline equipment, VHF field communications equipment, microwave substation controls and the installation of isolation equipment when installing Telus lines into substations. These installations will provide voice as well as data and control communications as required.

The communications budget also covers upgrades and/or replacement of equipment that is used for remote control and operation of field devices from the FortisBC System Control Centre.

Table 5.7 - Telecommunications

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	221	258	86	54	368	121	183	191	196	203	3,595

5.10 Buildings

FortisBC has 15 office/yard sites (ranging in age from 8 to 88 years) throughout the Kootenay, Boundary, Okanagan and Similkameen regions totaling approximately 229,500 square feet of office, shop and warehouse space and approximately 51 acres of yard space. Of this, 125,000 square feet is owned and 104,500 square feet is leased.

Building audits have been carried out at all sites to identify and prioritize maintenance and upgrade requirements. The audits contain location, age, square footage and description of each building component. After inspection, each component is rated in years for estimated life, effective life and remaining life.

All upgrades take into account immediate and long-term requirements that meet FortisBC standards to best serve customers and comply with BC Mandatory Reliability, BC Energy Plan and Public Safety Standards. FortisBC also commits to maintaining facility and yard assets in a responsible manner while providing employees with a worksite that meets FortisBC health, safety and environmental standards.

All facilities in the service area are considered in the planning process, including the FortisBC gas division locations. Changes in work processes, staffing requirements and integration of work crews and administrative staff are also recognized during the planning process.

Table 5.10 - Buildings

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	1,820	1,599	1,271	948	1,288	1,362	883	601	278	287	7,273

5.11 Furniture and Fixtures

This project is required for the replacement of deteriorated furniture and the addition/modification of furniture to accommodate changing needs within the organization. FortisBC has completed an inventory of furniture at all sites, categorizing the condition of the furniture into three categories - disposal, poor and good. Using this inventory together with the Company's Environment Health and Safety Standard 108, (Section 2.2) "Monitoring the Work Environment", the capital requirements are upgraded each year. Typically chairs are replaced every five years and workstations are reviewed for functionality every 8 to 10 years.

Table 5.11 - Furniture and Fixtures

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	248	237	294	268	182	121	122	508	105	108	2,071

5.12 Tools and Equipment

This project involves the purchase of tools and equipment necessary to construct, operate, and maintain the generation, transmission, and distribution system. It encompasses all capital expenditures for tools and equipment in excess of $1,000 and includes replacement tools that have reached the end of their service life, as well as additional tools that are more appropriate for the various trades from an ergonomic and/or safety perspective.

Table 5.12 - Tools and Equipment

Year	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017-31
	($000s)										
Cost	936	587	525	507	622	528	457	477	491	508	8,236

Appendix A

Glossary

Abbreviations

2005 SDP 2005-2024 System Development Plan

AACE Association for the Advancement of Cost Engineering

AMI Advanced Metering Infrastructure

BCH BC Hydro

BCTC British Columbia Transmission Corporation

BCUC British Columbia Utilities Commission

BI Business Intelligence

CEA Canadian Electrical Association

CGAAP Canadian Generally Accepted Accounting Principles

CMMS Computerized Maintenance Management System

CPA Canal Plant Agreement

CPC Columbia Power Corporation

CPI Consumer Price Index

CPCN Certificate of Public Convenience and Necessity

CSIS Canadian Security Intelligence Service

CVR Conservation Voltage Reduction

DSM Demand Side Management

DFO Department of Fisheries and Oceans

DG Bell DG Bell Terminal Station

Abbreviations

EMF Electromagnetic Field

EH&S Environment, Health and Safety

FA Lee FA Lee Terminal Station

FERC Federal Energy Regulatory Commission

FOR Forced Outage Rate

GIS Geographic Information System

GEID Glenmore-Ellison Irrigation District

GWh gigawatthour

HES Head End System

HV High Voltage

ICNIRP International Commission on Non-Ionizing Radiation Protection

IEEE Institute of Electrical and Electronic Engineers

IFRS International Financial Reporting System

IRU Indefeasible Right of Use

ISP Integrated System Plan

kcmil Thousand Circular Mil (wire size; formerly MCM)

kV kilovolt

kVA kilovoltampere

LAN Local Area Network

Abbreviations

MDMS Meter Data Management System

MOCB Minimum Oil Circuit Breaker

MRS Mandatory Reliability Standards

MVA megavoltampere

MW megawatt

NASPI North American Synchrophasor Initiative

NERC North American Electric Reliability Corporation

N-0 Normal Operating Conditions

O&M Operating and Maintenance

OATT Open Access Transmission Tariff

OCB Oil Circuit Breaker

PCB Polychlorinated biphenyls

OTR Okanagan Transmission Reinforcement

Q1 First Quarter

Q2 Second Quarter

Q3 Third Quarter

Q4 Fourth Quarter

RAS Remedial Action Scheme

RoW Right-of-Way

Abbreviations

SAIDI System Average Interruption Duration Index

SAIFI System Average Interruption Frequency Index

SARA Species at Risk Act

SCADA Supervisory Control and Data Acquisition

SCC System Control Centre

SDP System Development Plan

SVC Static VAR Compensator

T&D Transmission and Distribution

TDM Time Division Multiplexing

ULE Upgrade and Life Extension

VAC Volts Alternating Current

VHF Very High Frequency

VVO Voltage and Var Optimization

WAN Wide Area Network

WECC Western Electricity Coordinating Council

Glossary of Terms

British Columbia Transmission Corporation (BCTC) – A provincial Crown corporation, formed in May 2003, responsible for managing, operating, planning and maintaining most of the provincial electrical power transmission system and its interconnections with the larger North American grid.

British Columbia Utilities Commission (Commission) – The British Columbia Utilities Commission is an independent regulatory agency of the Provincial Government that operates under and administers the Utilities Commission Act. The Commission's primary responsibility is the regulation of British Columbia's natural gas and electricity utilities to ensure that the rates charged for energy are fair, just and reasonable, and that utilities provide safe, adequate and secure service to their customers.

Bulk transmission – Transmission equipment that is used to transport large amounts of electrical power, typically between generating, terminal or switching stations.

Bus - A conductor, which may be a solid bar or pipe, normally made of aluminum or copper, used to connect one or more circuits to a common interface. An example would be the bus used to connect a substation transformer to the outgoing circuits.

Bus split – a bus that is split by a circuit breaker or other switch.

Bus-tie (or bus-coupler) circuit breaker – A circuit breaker connecting two buses.

Distribution – In FortisBC, high voltage equipment energized at 35 kV or below.

Double contingency security - A power system is able or secure enough to continue to supply customer load even in the event of the loss of two major transmission components.

Electromagnetic Field (EMF) – The electric and magnetic fields that exist wherever energized electrical equipment or appliances are located. The electric fields are associated with voltage; and the magnetic fields are associated with the amount of current being used.

kcmil – A cmil is the area of a circle with a diameter of one mil (1/1000 inch), used to describe the cross-sectional area of a conductor. One cmil equals approximately 0.0000008 square inches, a kcmil is 1,000 cmils.

kV - A kilovolt (kV) is 1,000 volts. A volt is unit of electromotive force defined as the electrical potential needed to produce one ampere of current with a resistance of one ohm.

MW – Mega watt = One million watts (see “Real Power”).

Mvar - One million vars (see “Reactive Power”).

Mega Volt-Amp (MVA) - Electrical capacity or electrical load, expressed as Volts x Amps. Volt Ampere rating designates the output which a transformer can deliver at rated voltage and frequency without exceeding a specified temperature rise. Also referred to as “apparent power”. An MVA is 1,000,000 VA.

N-0 – All major elements of the power system are required to be in service to avoid a load loss (customer outage).

N-1 - Outage of a single element with all other elements of the power system in service (a single transmission line, transformer, generating unit, power conditioning unit like a shunt capacitor bank, a shunt reactor bank, a series capacitor, a series reactor, etc.) with no load loss. This is a normal bulk transmission system design criteria.

N-2 - Simultaneous outage of two elements of a power system e.g. the simultaneous outage of both circuits of a double circuit transmission line or outage of two single circuit transmission lines on a common right of way due to outage events like lightning. This is a transmission system design criteria also used for a major urban centre with the difference from N-1-1 being the size of the sudden, or transient change in the supply capacity that the system must be able to ride through with no customer load loss.

Power wheeling - The use of the transmission facilities of one system to transmit power and energy by agreement of, and for, another system generally with a corresponding wheeling charge.

Reactive power - A component of apparent power (volt-amps) which does not produce any real power (watts) transfer. It is proportional to the sine of the phase angle between the current and the voltage and is measured in vars (volt-amps reactive).

Real power - A component of apparent power (volt-amps) which is capable of performing real work. It is measured in Watts.

Remedial Action Scheme (RAS) – An automatic system that reacts to disconnected load or generation to balance the electrical system, typically after an unplanned outage of a transmission line or a generator. As the power system load and generation must always be balanced, these schemes help prevent system-wide collapses (blackouts).

Ring-bus configuration – A Bus configured in a ring to allow a circuit breaker or device to be removed from service while power can flow the other direction around the ring to maintain service.

Single contingency security – A power system is able or secure enough to continue to supply customer load even in the event of the loss of one major transmission component.

Static VAR Compensator (or SVC) - Is an electrical device for providing fast-acting reactive power compensation to regulate voltage within the prescribed limits voltage and contribute to steady-state stability on high-voltage electricity transmission networks. The term "static" refers to the fact that the SVC has no moving parts other than circuit breakers and disconnects. The dynamic nature of the SVC lies in the use of thyristors which can switch capacitors or inductors in and out of the circuit on a per-cycle basis, allowing for very fast and fine control of system voltage.

Step-down / step-up transformer - A power transformer that converts from one voltage level to another, referred to as “stepping up” or stepping down” the voltage.

Substation – In FortisBC, a site that provides transformation from a transmission-level voltage to a distribution-level voltage.

Subtransmission – transmission level equipment (lines or transformers) that typically is used to provide a supply source only for distribution substations (i.e. not part of the bulk transmission system).

Switching station - In FortisBC, a site that provides switching or fault protection for transmission lines. No transformation is installed.

Terminal Station – In FortisBC, a site that provides transformation from one transmission-level voltage to another transmission-level voltage.

Terrestrial Habitat – The land environment used by animals and plants.

Transmission – In FortisBC, all electrical equipment energized at a voltage of greater than 35 kV.

Transformer Tertiary winding - A power transformer typically has two windings (a primary and secondary) to convert from one voltage level to another. Some transformers are equipped with a third (tertiary) winding for harmonic control or to provide a third lower voltage supply that is usually a fraction of the main winding’s capacity.

Transmission rebuild - To rebuild a section of, or the entire transmission line to current standards. A rebuild can include relocation or reconfigure a section of transmission line. Rebuilds and rehabilitations are similar; however rebuild projects involve a larger work scope, justifying them as standalone projects. Rebuilds may also include the replacement of conductor depending on conductor condition, while a rehabilitation project will not involve reconductoring. Transmission rebuilds are driven by condition-related issues and are part of the sustainment capital program.

Transmission rehabilitation - To rehabilitate a transmission line to a state where it is able to provide reliable service for another eight years, until the next condition assessment cycle. The Transmission Rehabilitation program is an ongoing capital sustainment program that rehabilitates all deficiencies identified as part of the Transmission Condition Assessment program.

Transmission reconductor - To reconductor a transmission line to larger conductor size to accommodate additional load. Reconductoring projects may require replacing structures to hold the additional weight of larger conductor. Reconductoring projects are growth driven.

var - A var is a component of apparent power (volt-amps) which does not produce any real power (watts) transfer. It is proportional to the sine of the phase angle between the current and the voltage.

Station Information

Designation	Station Name	Owner
AAL	Lambert, A. A. Terminal	FBC
ASM	Mawdsley, A.S. Terminal	FBC
AWA	Arawana Substation	FBC
AXR	Apex Repeater	FBC
BAR	Baldy Repeater	FBC
BEN	Bentley Terminal	FBC
BEP	Beaver Park Substation	FBC
BEV	Benvoulin Substation	FBC
BGR	Blue Grouse Repeater	FBC
BLK	Black Mountain Substation	FBC
BLR	Blue Mountain Repeater	FBC
BLU	Blueberry Substation	FBC
BRL	Braeloch Substation	FBC
BWR	Big White Repeater	FBC
BWS	Big White Substation	FBC
CAS	Castlegar Substation	FBC
CHR	Christina Lake Substation	FBC
COF	Coffee Creek Substation	FBC
COR	Corra Linn Generating Station	FBC
COT	Cottonwood Substation	FBC
CRA	Crawford Bay Substation	FBC
CRE	Creston Substation	FBC
CSC	Cascade Substation	FBC
DGB	Bell, D.G. Terminal	FBC
DUC	Duck Lake Substation	FBC
ELL	Ellison Substation	FBC
FRU	Fruitvale Substation	FBC
GFT	Grand Forks Terminal	FBC
GLE	Glenmore Substation	FBC
GLM	Glenmerry Substation	FBC
GRA	Granite Substation	FBC
GRE	Greenwood Substation	FBC
GRS	Greenwood Distribution Stepdown	FBC
HED	Hedley Substation	FBC
HER	Hearns Substation	FBC
HOL	Hollywood Substation	FBC
HUT	Huth Substation	FBC
JOR	Joe Rich Substation	FBC
KAL	Kaleden Substation	FBC
KAS	Kaslo Substation	FBC
KER	Keremeos Substation	FBC
KET	Kettle Valley Substation	FBC
KMR	Kobau Mountain Repeater	FBC
LBO	Lower Bonnington Generating Station	FBC
LEE	Lee, F.A. Terminal	FBC
M12	12 MVA Mobile Substation	FBC
M18	18 MVA Mobile Substation	FBC
M25	25 MVA Mobile Substation	FBC

Station Information

Designation	Station Name	Owner
M32	32 MVA Mobile Substation	FBC
M6.5	6.5 MVA Mobile Substation	FBC
MCM	McKinney Microwave Substation	FBC
MDY	Midway Distribution Stepdown	FBC
MID	Midway Substation	FBC
MMR	Midgeley Mountain Repeater	FBC
MSR	Missezula Repeater	FBC
NAR	Naramata Substation	FBC
NKM	Nk'Mip Substation	FBC
NKW	Mt. Nkwala Repeater	FBC
NWD	North Warfield Substation	FBC
OKF	OK Falls Substation	FBC
OKM	OK Mission Substation	FBC
OLI	Oliver Substation	FBC
OOT	Ootischenia Substation	FBC
OSO	Osoyoos Substation	FBC
PAS	Passmore Substation	FBC
PAT	Paterson Substation	FBC
PIN	Pine Street Substation	FBC
PLA	Playmor Substation	FBC
PMR	Phoenix Mountain Repeater	FBC
PPR	Pilot Point Repeater	FBC
PRI	Princeton Substation	FBC
REC	Recreation Substation	FBC
RGA	Anderson, R.G. Terminal	FBC
RMR	Red Mountain Repeater	FBC
ROC	Rock Creek Substation	FBC
ROS	Rossland Substation	FBC
RSM	Rosemont Switching Station	FBC
RUC	Ruckles Substation	FBC
SAL	Salmo Substation	FBC
SAU	Saucier Substation	FBC
SEX	Sexsmith Substation	FBC
SLC	South Slocan Generating Station	FBC
SLO	Slocan City Substation	FBC
SMR	Santa Rosa Repeater	FBC
SRR	Slocan Ridge Repeater	FBC
STC	Stoney Creek Substation	FBC
SUM	Summerland Substation	FBC
TAR	Tarrys Substation	FBC
TRA	Trail Substation	FBC
TRC	Trout Creek Substation	FBC
TUR	Tulameen Repeater	FBC
UBO	Upper Bonnington Generating Station	FBC
USS	Upper Bonnington Switching Station	FBC
VAL	Valhalla Substation	FBC
VAS	Vaseux Lake Terminal	FBC
WAR	Warfield Substation	FBC

Station Information

Designation	Station Name	Owner
WAT	Waterford Substation	FBC
WEB	West Bench Substation	FBC
WES	Westminster Substation	FBC
WHI	Whitewater Substation	FBC
WTS	Warfield Terminal Station	FBC
WYN	Wynndel Substation	FBC
YMR	Ymir Substation	FBC
YRT	Ymir Repeater	FBC
WAX	Waneta Expansion Generating Station	FTS
WDN	Walden North Generating Station	FTS
KRE	COK - Recreation Substation	COK
KSA	COK - Saucier Substation	COK
KSP	COK - Spall Substation	COK
ALH	Arrow Lakes Hydro Generating Station	CPC
BRD	Brilliant Generating Station	CPC
BRX	Brilliant Expansion Generating Station	CPC
BSS	Brilliant Switching Station	CPC
BTS	Brilliant Terminal Station	CPC
BCG	BC Gas (Terasen) Substation	CUST
BRA	Roxul (Bradford) Substation	CUST
KRA	Kraft Substation	CUST
WST	Westar Substation	CUST
ESS	Emerald Switching Station	TECK
TSS	Tadanac Switching Station	TECK
WAN	Waneta Generating Station	TECK
WHS	Waneta Hydro Station	TECK
WSS	Warfield Switching Station	TECK

Appendix B

Distribution Load Forecast

North Okanagan Distribution Load Forecast (Winter)

North Okanagan	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
SEX T1	29,001	29,450	28,418	29,635	30,655	31,780	32,695	33,622	34,487	46,173
GLE T2	19,412	24,520	25,819	27,343	28,195	28,594	30,091	30,944	31,686	42,308
GLE T3	27,661	28,243	29,061	30,017	30,935	31,802	32,492	33,189	33,855	42,607
HOL T1	30,101	26,742	28,096	29,312	31,770	32,888	33,792	34,750	35,664	47,759
HOL T3	19,431	16,400	17,213	17,885	18,655	19,312	19,816	20,378	20,910	28,010
DGB T1	20,271	28,265	29,437	30,448	31,348	32,214	33,626	34,580	35,370	47,268
DUC T1	8,090	6,350	7,185	7,556	7,795	8,050	8,281	8,516	8,751	11,713
DUC BCH	-	35,700	36,700	37,200	37,400	37,600	37,700	37,800	38,100	40,381
JOR T1	3,157	3,330	3,489	3,636	3,778	3,906	4,018	4,132	4,239	5,676
OKM T1	23,821	23,614	25,751	27,178	27,904	28,717	29,255	29,952	30,575	38,549
OKM T2	11,283	10,301	10,745	11,242	11,671	11,835	12,363	12,699	13,022	17,420
LEE tert	14,921	14,921	14,790	15,414	10,947	11,316	11,642	11,972	12,281	16,446
BLK T1	12,299	12,691	13,349	13,974	16,255	16,633	17,155	17,661	18,128	24,260
ELL T1	14,625	14,988	20,364	21,611	22,874	24,574	24,967	25,728	26,436	35,404
BWS T1	13,719	16,281	16,964	17,558	18,010	19,134	19,484	20,003	20,502	27,495
BEV T1	-	19,480	20,493	21,457	22,417	23,327	23,731	24,450	25,118	33,638
REC T1/T2	27,953	29,307	30,341	33,933	34,839	35,372	36,037	36,565	37,042	43,331
SAU T1	23,000	25,570	26,966	28,065	28,652	28,990	29,567	30,010	30,419	35,566
Totals	**298,746**	**366,152**	**385,183**	**403,462**	**414,099**	**426,045**	**436,711**	**446,953**	**456,585**	**584,004**

Note: All loads shown in kVA. Winter 2011 indicates 2011/12 winter season, etc.

South Okanagan Distribution Load Forecast (Winter)

South Okanagan	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
RGA T3	16,280	16,512	16,708	16,955	17,152	17,293	17,431	17,571	17,707	19,236
OKF T1	9,985	10,074	10,170	10,270	10,311	10,506	10,574	10,647	10,720	11,653
WEB T1	7,181	8,833	9,268	9,341	9,399	9,434	9,531	9,650	9,705	10,537
AWA T1	7,252	7,413	7,521	7,792	7,813	7,824	7,902	7,981	8,057	8,736
KAL T1	6,600	6,689	6,780	7,261	7,340	8,020	8,085	8,150	8,209	8,920
SUM T2	18,121	18,499	18,749	18,972	19,181	19,364	19,521	19,677	19,820	21,536
WAT T1	17,523	17,760	18,001	18,215	18,415	18,590	18,741	18,891	19,029	20,676
WES T1/T2	24,262	24,683	25,017	25,315	25,593	25,837	26,046	26,255	26,446	28,736
TRC T1	6,786	7,261	7,232	7,145	7,014	7,421	7,433	7,446	7,471	8,145
PIN T1	7,604	7,626	7,730	7,822	7,908	7,983	8,048	8,112	8,171	8,879
PIN T2	12,741	15,055	15,211	15,355	15,553	15,727	15,841	15,959	16,074	17,472
OSO T1	7,321	7,420	7,520	7,610	7,694	7,767	7,830	7,751	7,803	8,481
OSO T2	9,385	5,061	5,129	5,191	5,248	5,298	5,341	5,383	5,422	5,892
NKM T1	6,758	10,690	11,321	11,943	12,495	12,668	12,768	12,867	12,957	14,079
KER T1	13,002	12,948	13,525	13,848	13,907	13,881	14,028	14,214	14,321	15,531
HED T1	5,216	5,521	5,570	5,605	5,628	5,694	5,772	5,807	5,842	6,350
OLI T1	9,457	8,287	8,239	8,555	8,930	8,902	8,838	8,927	9,049	9,821
PRI T4	18,657	20,608	20,835	21,019	21,172	21,506	21,659	21,814	21,963	23,875
HUT T4/5/6/7	9,646	9,777	9,909	10,027	10,137	10,234	10,317	10,399	10,475	11,382
HUT T8	7,000	7,095	7,191	7,276	7,356	7,426	7,487	7,547	7,601	8,260
Totals	**220,777**	**227,811**	**231,627**	**235,514**	**238,246**	**241,375**	**243,191**	**245,048**	**246,840**	**268,198**

Note: All loads shown in kVA. Winter 2011 indicates 2011/12 winter season, etc.

Kootenay Distribution Load Forecast (Winter)

Kootenay	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
KAS T1	8,815	9,189	9,197	9,399	9,527	9,533	9,581	9,640	9,714	10,335
COF T3	6,276	6,479	6,642	6,690	6,725	6,748	6,807	6,860	6,892	7,336
CRA T5	6,577	6,767	6,811	6,969	7,015	7,052	7,079	7,128	7,180	7,639
CRE T1	13,279	13,532	13,683	13,784	13,975	14,038	14,114	14,204	14,284	15,212
CRE T2	11,879	13,108	13,305	13,426	13,492	13,601	13,689	13,779	13,851	14,747
AAL T2	14,207	14,461	13,969	13,997	14,124	14,191	14,471	14,440	14,510	15,470
VAL T1	4,543	4,841	4,890	4,934	4,975	5,011	5,042	5,072	5,100	5,431
VAL T2	4,581	4,627	4,674	4,716	4,755	4,790	4,819	4,848	4,875	5,191
PAS T1	3,547	3,520	3,528	3,539	3,696	3,657	3,669	3,691	3,718	3,962
PLA T1	13,533	13,723	13,830	13,960	14,066	14,193	14,270	14,352	14,432	15,369
TAR T1	3,000	2,959	2,950	2,940	2,928	2,955	2,947	2,944	2,943	2,945
COT T1	594	663	670	676	682	687	691	695	699	744
SAL T1	7,405	7,559	7,648	7,657	7,757	7,835	7,865	7,911	7,950	8,472
HER T1	1,832	1,857	1,876	1,893	1,909	1,922	1,934	1,946	1,957	2,084
FRU T1	6,000	7,163	7,075	7,052	6,988	6,892	7,195	7,185	7,194	7,660
YMR T1	1,387	1,482	1,497	1,511	1,523	1,534	1,544	1,553	1,562	1,663
CAS T1	12,045	12,149	12,106	12,148	12,487	12,522	12,560	12,617	12,699	13,534
BLU T1	7,940	8,083	8,183	8,246	8,303	8,374	8,424	8,476	8,520	9,073
OOT T1	8,307	9,442	9,511	9,564	9,694	9,782	9,816	9,871	9,927	10,576
BEP T1	8,440	10,886	9,475	9,590	9,664	8,823	8,846	8,910	10,078	10,729
GLM T1	11,216	11,818	14,081	14,163	14,240	14,328	14,429	14,540	14,607	15,552
STC T1	7,700	8,458	8,457	8,414	8,690	8,621	8,721	8,756	8,801	9,381
CSC T1	10,330	10,849	10,947	10,950	11,005	11,160	11,231	11,285	11,333	12,078
Totals	**173,433**	**183,614**	**185,007**	**186,217**	**188,218**	**188,249**	**189,743**	**190,705**	**192,826**	**205,181**

Note: All loads shown in kVA. Winter 2011 indicates 2011/12 winter season, etc.

Boundary Distribution Load Forecast (Winter)

Boundary	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
CHR T1	4,884	4,968	5,015	5,057	5,097	5,131	5,160	5,189	5,216	5,531
RUC T1	6,699	6,806	6,920	7,130	7,125	7,101	7,164	7,223	7,273	7,696
RUC T2	9,140	8,877	8,939	9,191	9,294	9,313	9,314	9,386	9,462	10,019
GFT T3	9,964	10,883	10,986	11,079	11,165	11,240	11,304	11,368	11,426	12,116
KET T1/T2	11,354	11,660	11,734	11,787	11,887	12,041	12,071	12,131	12,191	12,935
Totals	**42,041**	**43,194**	**43,594**	**44,244**	**44,567**	**44,825**	**45,014**	**45,297**	**45,568**	**48,297**

Note: All loads shown in kVA. Winter 2011 indicates 2011/12 winter season, etc.

North Okanagan Distribution Load Forecast (Summer)

North Okanagan	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
SEX T1	25,810	27,667	26,209	27,334	28,579	29,459	30,521	31,579	32,490	46,064
GLE T2	22,820	25,180	26,595	27,727	29,098	30,298	31,302	32,388	33,310	47,210
GLE T3	26,458	28,614	29,640	30,772	31,423	32,219	32,983	33,817	34,550	44,731
HOL T1	20,953	21,745	22,918	24,259	26,322	27,247	28,137	29,113	30,030	42,561
HOL T3	22,470	16,819	17,687	18,650	19,367	20,071	20,664	21,380	22,049	31,271
DGB T1	21,734	24,098	25,253	26,317	27,181	28,450	29,312	30,328	31,213	44,244
DUC T1	-	5,079	5,840	6,029	6,428	6,576	6,784	7,019	7,238	10,266
DUC BCH	-	28,553	29,827	29,684	30,843	30,717	30,886	31,158	31,514	35,393
JOR T1	1,706	1,787	1,881	1,971	2,050	2,123	2,190	2,266	2,335	3,311
OKM T1	19,617	21,473	23,301	24,507	24,959	25,410	26,063	26,644	27,164	34,396
OKM T2	12,474	9,287	9,733	10,356	10,743	11,094	11,428	11,834	12,221	17,306
LEE tert	12,665	13,340	13,197	13,830	9,312	9,644	9,949	10,294	10,611	15,042
BLK T1	11,289	10,909	11,373	11,779	13,552	14,718	14,844	15,325	15,785	22,439
ELL T1	18,915	14,121	19,371	20,592	21,709	23,241	23,917	24,757	25,526	36,188
BWS T1	2,578	3,884	4,111	4,335	4,543	4,676	4,808	4,984	5,144	7,289
BEV T1	-	19,480	20,587	21,675	22,663	23,625	24,101	24,983	25,790	36,564
REC T1/T2	20,821	25,868	26,570	29,444	29,430	29,136	30,138	30,281	30,347	32,679
SAU T1	21,597	24,265	25,820	26,411	26,351	26,209	26,776	27,008	27,112	29,180
Totals	**261,907**	**322,168**	**339,910**	**355,674**	**364,553**	**374,915**	**384,803**	**395,157**	**404,430**	**536,134**

Note: All loads shown in kVA.

South Okanagan Distribution Load Forecast (Summer)

South Okanagan	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
RGA T3	13,296	16,971	17,145	17,306	17,564	17,668	17,883	18,036	18,184	20,062
OKF T1	7,371	8,405	8,557	8,594	8,847	8,662	8,888	8,970	9,038	9,964
WEB T1	8,878	8,560	8,882	8,999	9,096	9,235	9,238	9,362	9,442	10,413
AWA T1	4,201	4,612	4,712	4,763	4,803	4,882	4,905	4,957	4,997	5,514
KAL T1	3,859	4,999	5,072	5,540	5,601	6,266	6,321	6,382	6,437	7,100
SUM T2	12,541	13,614	13,814	13,998	14,153	14,294	14,419	14,558	14,683	16,195
WAT T1	16,732	16,978	17,227	17,457	17,650	17,825	17,982	18,155	18,310	20,196
WES T1/T2	19,146	19,810	20,101	20,369	20,595	20,799	20,982	21,184	21,365	23,566
TRC T1	5,623	6,398	6,471	6,370	6,564	6,594	6,686	6,733	6,773	7,486
PIN T1	6,974	7,914	8,030	8,137	8,227	8,309	8,382	8,463	8,535	9,414
PIN T2	9,824	12,974	13,097	13,292	13,446	13,625	13,709	13,835	13,960	15,400
OSO T1	7,840	7,953	8,070	7,931	8,031	8,115	8,423	8,272	8,339	9,203
OSO T2	7,870	6,820	6,920	7,012	7,090	7,160	7,223	7,293	7,355	8,113
NKM T1	9,247	14,196	14,899	15,593	16,228	16,350	16,545	16,700	16,838	18,569
KER T1	10,537	11,803	12,003	12,298	12,362	12,565	12,594	12,734	12,860	14,176
HED T1	1,707	2,221	2,238	2,223	2,193	2,248	2,296	2,307	2,316	2,559
OLI T1	7,006	7,322	7,429	7,528	7,611	7,688	7,755	7,829	7,896	8,710
PRI T4	12,648	18,071	18,192	18,259	18,249	18,512	18,841	18,962	19,082	21,062
HUT T4/5/6/7	9,419	9,557	9,698	9,827	9,936	10,034	10,122	10,220	10,308	11,369
HUT T8	7,108	7,212	7,318	7,416	7,498	7,572	7,639	7,713	7,779	8,580
Totals	**181,827**	**206,391**	**209,875**	**212,913**	**215,744**	**218,403**	**220,834**	**222,666**	**224,498**	**247,651**

Note: All loads shown in kVA.

Kootenay Distribution Load Forecast (Summer)

Kootenay	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
KAS T1	5,090	4,694	4,579	4,533	4,696	4,567	4,668	4,659	4,672	4,849
COF T3	4,500	4,907	4,911	4,951	4,947	5,006	5,002	5,018	5,036	5,223
CRA T5	2,700	3,677	3,636	3,580	3,708	3,770	3,717	3,722	3,737	3,886
CRE T1	7,800	8,491	8,680	8,863	8,877	8,910	8,866	8,936	8,982	9,301
CRE T2	6,500	9,227	9,226	9,412	9,404	9,435	9,450	9,489	9,535	9,877
AAL T2	8,600	8,926	8,581	8,148	8,261	8,425	8,569	8,489	8,464	8,825
VAL T1	2,000	2,065	2,076	2,086	2,095	2,103	2,109	2,117	2,124	2,202
VAL T2	5,349	5,402	5,432	5,459	5,481	5,501	5,519	5,538	5,556	5,761
PAS T1	2,050	2,631	2,629	2,501	2,649	2,798	2,672	2,679	2,687	2,806
PLA T1	6,000	6,256	6,205	6,151	6,184	6,201	6,272	6,271	6,280	6,519
TAR T1	3,360	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000	3,000
COT T1	165	262	263	264	266	267	267	268	269	279
SAL T1	4,800	5,251	5,208	5,194	5,219	5,249	5,285	5,289	5,301	5,502
HER T1	700	1,077	1,082	1,088	1,092	1,096	1,100	1,104	1,107	1,148
FRU T1	4,600	4,292	4,261	4,131	4,187	4,235	4,271	4,263	4,261	4,432
YMR T1	750	763	767	770	774	776	779	782	784	813
CAS T1	8,900	8,870	8,807	8,927	9,131	9,103	9,072	9,107	9,161	9,498
BLU T1	5,960	5,683	5,707	5,736	5,751	5,765	5,795	5,814	5,831	6,046
OOT T1	4,980	5,042	5,058	5,070	5,075	5,096	5,128	5,141	5,154	5,345
BEP T1	7,900	10,137	8,560	8,522	8,586	7,735	7,769	7,780	8,885	9,222
GLM T1	10,000	10,532	12,676	12,947	12,995	12,906	12,910	13,029	13,091	13,547
STC T1	6,061	5,275	5,273	5,262	5,637	5,562	5,465	5,499	5,541	5,753
CSC T1	4,400	5,031	4,991	4,933	4,985	5,063	5,059	5,061	5,072	5,269
Totals	**113,165**	**121,490**	**121,609**	**121,531**	**123,000**	**122,567**	**122,747**	**123,057**	**124,530**	**129,104**

Note: All loads shown in kVA.

Boundary Distribution Load Forecast (Summer)

Boundary	Base Year	Year 0	Year 1	Year 2	Year 3	Year 4	Year 5	Year 6	Year 7	Year 20
	2010	2011	2012	2013	2014	2015	2016	2017	2018	2031
CHR T1	4,366	4,444	4,517	4,586	4,643	4,695	4,742	4,794	4,840	5,407
RUC T1	6,600	6,502	6,664	6,842	6,865	7,013	7,020	7,113	7,191	8,028
RUC T2	8,380	8,411	8,662	8,806	8,857	8,967	9,055	9,170	9,255	10,335
GFT T3	6,600	7,154	7,272	7,382	7,475	7,558	7,634	7,717	7,792	8,705
KET T1/T2	3,400	5,889	5,738	5,523	5,225	5,273	5,736	5,688	5,662	6,343
Totals	**29,346**	**32,399**	**32,854**	**33,138**	**33,065**	**33,507**	**34,187**	**34,482**	**34,739**	**38,819**

Note: All loads shown in kVA.

Summer and Winter “1-in-20” Peak Load Forecasts

Year	Summer Peak	Winter Peak
	(MW)	
2011	652	843
2012	661	856
2013	669	869
2014	678	880
2015	685	890
2016	688	895
2017	692	902
2018	697	910
2019	703	918
2020	708	926
2021	714	935
2022	720	943
2023	726	951
2024	732	960
2025	738	969
2026	744	977
2027	750	986
2028	756	995
2029	763	1004
2030	769	1013
2031	775	1022
2032	782	1031
2033	788	1041
2034	795	1051
2035	802	1061
2036	808	1071
2037	815	1081
2038	823	1092
2039	830	1103
2040	837	1113

Appendix C

Spatial Load Forecasting (Kelowna)

Spatial Electric Load Forecasting
Kelowna, B.C.

Preliminary Report

Prepared By
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Prepared For
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Date Revised
June 8, 2011

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1 Executive Summary

Spatial Electric Load Forecasting is a process of "predicting" future electrical loads. It answers the three questions about growth: how much, when and where. The purpose of forecasting is to help planners and engineers build optimal upgrades at the best time and in the best location. This ultimately benefits their customers, the ratepayers and the entire company.

Spatial forecasting methodologies can be classified as trending, simulation or hybrid methods. The software tool used for the Kelowna FortisBC area, LoadSEER, is a hybrid forecasting tool.

Base models have been created for the Kelowna area. These base models can be entirely statistical and based only upon historic growth patterns or they can consider other factors based on local knowledge, municipal plans, zoning and so on.

Hourly weather normalized loads can be applied to each customer type on an acre-by-acre basis. The load densities combined with the future land use maps creates a forecasted peak load map result. This can be overlaid with substation or feeder polygons to determine a feeder-by-feeder forecast result in a tabulated format.

2 Objective

Spatial Electric Load Forecasting is a process of "predicting" future electrical loads in a service area. It helps planners answer three basic questions.

- **How much** power will be delivered?
- **When** will the power be delivered?
- **Where** will the power be delivered?

Load forecasting is essential for capacity, contingency planning and upgrades. Planning, designing, building transmission and distribution infrastructure can take from a couple years up to 25 years. For effective infrastructure and capacity upgrades it is necessary to understand how load may grow in the future.

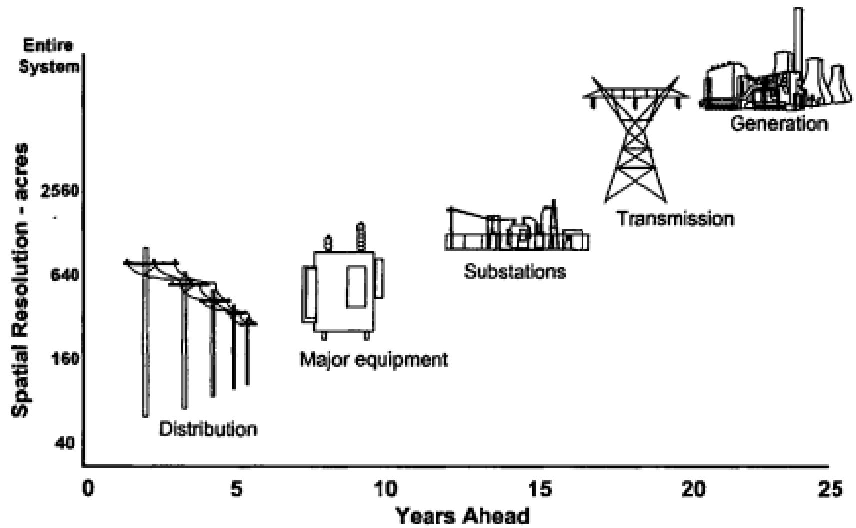

Figure 1 - It can be necessary to plan up to 25 years in advance for some types of transmission and distribution projects (Willis, 2002b)

Load forecasting relates to long term and short term planning. Short term planning addresses eminent capacity upgrades and infrastructure upgrades from one to five years. Long term planning gives perspective to short term planning and addresses future capacity requirements.

Why do Long-Term Planning? This is necessary to improve the long-term value of short-term planning. The long-term plan evaluates how well short term planning commitments fit into long-term needs. No commitment needs to be made to the elements in a long-term plan. Capacity and location are more important than timing in a long-term forecast. In other words, it is more important to know what will eventually be needed than to know exactly when it will be needed.

Long- term planning is done so you can answer questions such as:

- "Is this a good decision in the long run, or will we regret it only a few years after we build it?"
- "Do we need to allow for a second transformer in the new substation we will build in four years?"
- "How long will this be an effective solution to the problem?"
- "How much load will the feeder eventually need to serve?"
- "Will we need an additional substation near here in the future? Or will the new substation we're building now be sufficient forever?"

Distribution planning involves capacity and contingency planning. Capacity planning ensures that the power distribution system won't overload by ensuring it has sufficient conductor size for load levels, and by ensuring the voltage is sufficient at all points in the line for all of the feeders. Contingency planning ensures that load can be adequately served when a transformer or a substation fail. For more information on FortisBC capacity and contingency planning, refer to the Appendix: Devin Krenz Co-op Report.

2.1 Study Area Characteristics

The initial study area was defined by the City of Kelowna political boundary. This was chosen due to the completeness of the available data and the strategic benefit of the forecast. The Kelowna area is the fastest growing part of the FortisBC service area. The City of Kelowna political area has detailed current zoning, future land use and tax parcel data in an ESRI GIS format.

2.1.1 Quick Facts: City of Kelowna

2009 city population:	120,812
Population density:	571/km^2
Economy:	Service industry, tourism, wineries, university and college
	Third-largest metropolitan area in British Columbia
	One of the fastest growing cities in Canada from 2002-2008
Climate:	Dry, mild – “humid continental climate”, 300mm precipitation per year

Source: City of Kelowna Website, www.kelowna.ca

3 Background

FortisBC has two forecasting efforts: distribution and system level. The current distribution forecast is a bottom-up approach developed by the distribution engineers. The system level forecast is a part of the economic forecast and is developed by the revenue forecasting group.

The existing distribution forecast looks at summer and winter peaks by feeder annually. Feeder data is exported from the ION Enterprise system and Cascade. The forecast uses an Excel spreadsheet to perform straight-line trending using a growth rate factor assigned by the planner. It also accounts for “known” future developments. Refer to the Appendix: Distribution Load Forecast 2010

The system level forecast is development and managed by the revenue forecasting group. It forecasts customer growth rates, future GWh consumption, and peak kW for the entire FortisBC system. Refer to the Appendix: Revenue Forecast 2010.

4 Theory

There are three general types of spatial load forecasting: trending, simulation and hybrid.

4.1 Trending

Trending methods extrapolate past load growth patterns into the future. Curve-fitting is the most well known form of trending. Other types of trending methods include template matching pattern recognition and multivariate trending.

Common template matching methods use "S-curve" extrapolation. This involves comparing the recent load history of a small area "A" to another small area "B" with a long load history. The scheme matches the recent load trend history of area "A" to a similar trend found in the load history of area "B". It then extrapolates area "A" to match the trend found in area "B".

Multivariate trending attempts to improve electric load forecasting by tying the load variable to other company trends such as customer counts or economic growth.

Trending methods can also account for "special loads", which are unique one-time future load exceptions that are known to the planner. Extra care is required when trending with special loads to ensure the loads are not being double counted.

4.2 Simulation

In contrast to extrapolating past data, simulation techniques attempt to model the process of load growth itself. Often a de-coupled approach is used to separately model two growth factors:

- **Change in the number of customers** buying electric power (focus on *spatial* changes in power consumption)
- **Change in per capita consumption** among customers (focus on *temporal* changes in power consumption)

The two models are then combined to produce an overall load forecast.

Simulation forecasting involves three general steps:

- Global customer counts
- Interaction of classes
- Geographical land-use patterns

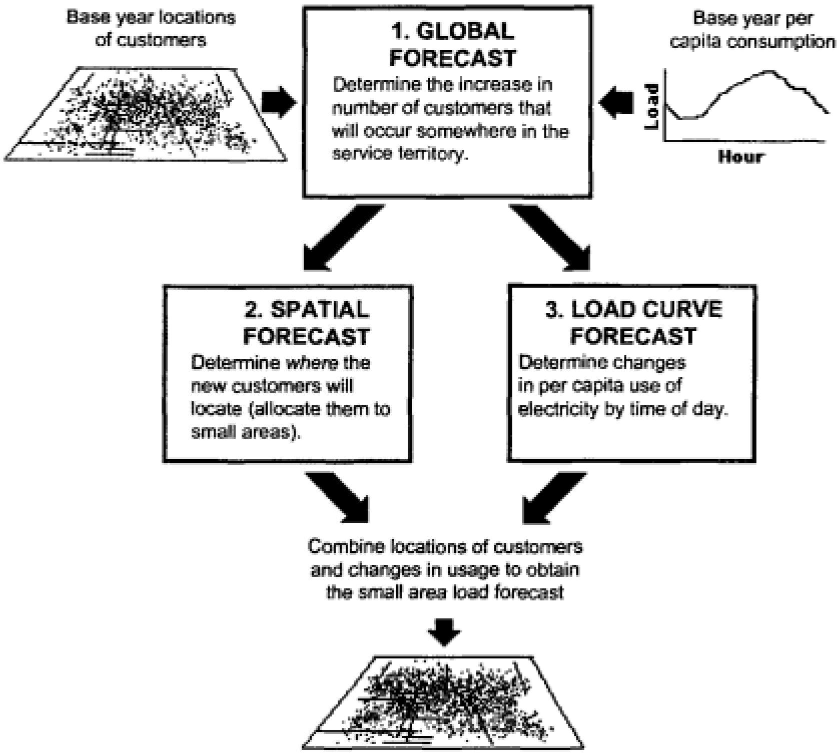

Figure 2 - Simulation methods project consumer locations and per capita consumption separately, and then combine the two to produce the final small area forecast

Simulation methods distinguish customers by class. Common types of Load Use Classes include *rate classes*, *per capita consumption classes*, and *spatial location classes.*

It is important to note that other planners often look at "expected values" whereas transmission and distribution planners must consider "worst case" scenarios. Electrical distribution systems are not designed to "just get by" under normal conditions, rather they are designed to "just get by" under worst case scenarios. For example, the distribution system must get by during the coldest winter day during dinner time on a week day.

4.3 Hybrid

Hybrid forecasting methods attempt to combine the benefits of trending and simulation to create a more efficient and accurate forecast.

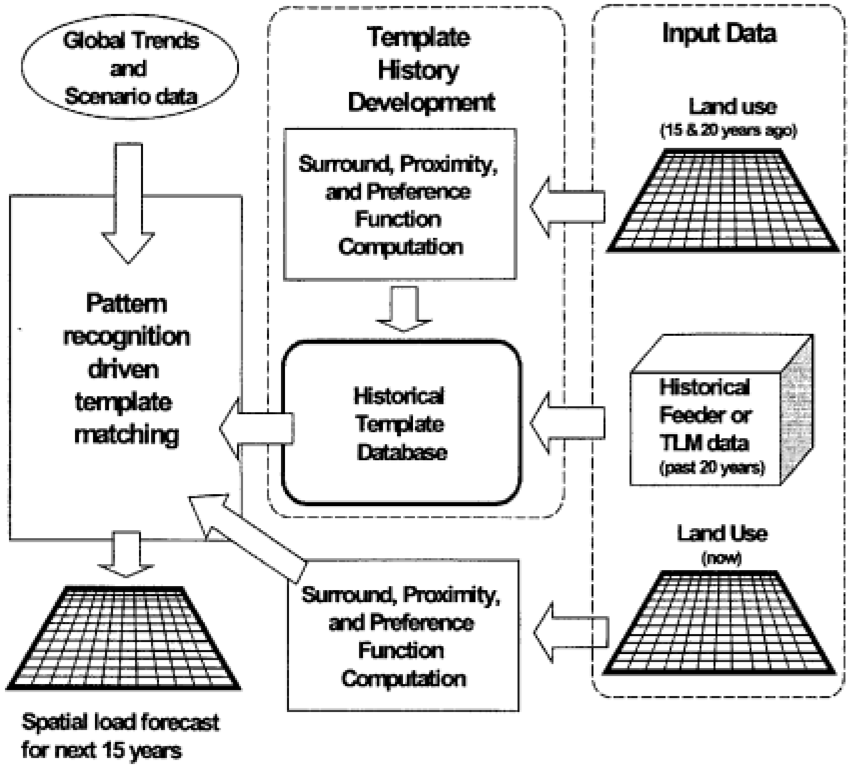

Figure 3 - An extended template matching algorithm that uses land-use data massaged by a simulation program's preference engine as its leading indicator data.

4.4 Small Area Forecasting

The location of load growth is determined by dividing the service area into "small areas". These can be square rectangles or any other irregular shape. The size of these "small areas" determines the resolution of the model.

4.5 Multiple Scenario Forecasting

Many events affecting load forecasts cannot be predicted accurately. For this reason it is recommended that planners perform multiple scenarios forecasting to determine "what-if" outcomes and evaluate each risk. For example, what would be the impact of a new bridge, a new aquatic center or an industrial plant closing down? Many of these cases are tied to political agendas and cannot be predicted with any certainty.

4.6 Planning Period

The planning period for generation can be up to 25 years, transmission up to 20 years, substations up to 15 years, major equipment up to 10 years, distribution up to 6 years and customer-level planning up to 3 years (see Figure 1). For this reason, it can be beneficial to produce forecasts that can predict loads up to 25 years in advance.

Naturally, as a model forecasts further into the future the accuracy of the forecast diminishes; therefore, it is beneficial to forecast at several different time periods. Forecasts in the near future are beneficial for distribution planning (i.e. feeder upgrades), whereas long term forecasts are beneficial for substation or transmission upgrades.

4.7 Recommendations for Load Forecasting Summary

1. Focus on the plan, not the forecast
2. Develop and use a rigorous, documented forecast procedure
3. Explicitly define all terms and definitions
4. Remain objective and unbiased
5. Document every forecast including data, method, and results
6. Weather-normalize all historical load records and forecasts
7. Make all forecasts in the company consistent with one another
8. Always use multi-scenario mindset
9. Study before forecasting
10. Keep recent events or changes in perspective
11. Use the forecast unaltered
12. Remain skeptical of all results
13. Build in continuous improvements

Comprehensive information about load forecasting topics can be obtained from Willis, H. Lee. (2002b). Spatial electric load forecasting. Raleigh, North Carolina, U.S.A.: CRC Press.

5 Building the Spatial Model

5.1 Units

Due to the software used for this project, imperial units are used for the spatial model. Use the following table to convert to metric units.

Table 1 -Units

From Unit	To Unit	Conversion Ratio
Acre	feet^2	43560 = 208.71^2
Acre	km^2	0.00404685642
Acre	mile	0.0015625
Mile	km	1.609344
Mile	feet	5280

5.2 Data Source for the Land Use Model

Table 2 – Data Sources

Data Type	Data Source	Date Extracted
Future Land Use: future zoning classes, parks, agriculture, etc.	City of Kelowna Official Community Plan 2020	June 2010
Land use base map: see Appendix	Satellite imagery from Integral Analytics	2010
Current zoning	City of Kelowna	June 2010
Transportation	ESRI	2010
ALR Land	BC Land Commission	July 2010
Raw developments	FortisBC and Primary Engineering distribution planners and designers in the Kelowna area	August 2010

5.3 The Land Use Model

5.3.1 Agricultural Land and the ALR

The Kelowna region has a significant amount of agricultural land. This land is used for orchards, vineyards, ranching, and other agricultural purposes. The Agricultural Land Commission is a provincial agency responsible for preserving agricultural land and encouraging farming within communities. The commission established the Agricultural Land Reserve (ALR) between 1874 and 1976 to protect agricultural land.

From 1973 to 2006, almost 15% of the original 10,054ha in Kelowna were excluded from the ALR for development (see Figure 39). It is known that is very difficult to exclude land from the ALR, especially if the land is suitable for farming. However, noting that 15% of Kelowna's ALR land has been successfully excluded, history would indicate that some development in the ALR should be expected.

In the deterministic models, a detraction factor was applied to all ALR land. This discourages growth in the ALR, but does not prohibit development if all other factors are strongly in favour.

In the pure statistical models, the historic growth land use trends dictate how growth will occur in agricultural land. It does not give any additional preference or detraction to ALR land. This would assume that land use growth will occur similar to the past 20 years.

5.3.2 City of Kelowna Future Land Use

The City of Kelowna future land use classification map, as shown in Figure 40, specifies where the city planners would like certain types of growth to occur. The LoadSEER model can use these classifications to encourage growth of certain types in certain areas. For example, future commercial growth will have a preference to developing in areas assigned as future commercial by the Official Community Plan (OCP).

Some models originally used the OCP agriculture map to discourage growth in agriculture land; however, the official ALR maps gave better results. Therefore, the ALR maps were used instead of the OCP agriculture classification for the model simulation.

5.4 Satellite Land Cover Imagery

Historic satellite images from 1990, 2000 and 2010 were converted into land cover ESRI shape files by Integral Analytics. The satellite images collect eight different spectrums of data, giving insight into the type of land use through the study area. Advanced imagery software is used to analyse imagery into grouped sections by similar land use. These sections are further grouped and classified into customer classes.

Since this land cover imagery analysis was the first one to be performed in Canada, there were some challenges accordingly. One major issue was the classification of commercial and agriculture. Some agriculture land appears to be very barren from the satellite imagery and has similar characteristics to commercial parking lots. Initially, this resulted in classifying agriculture land as commercial. More analysis was then required to correct this problem.

Using satellite imagery for land cover classification also has challenges distinguishing between high density residential (apartments, etc.) and some commercial offices. So the classification of "commercial" also includes some high density residential.

Using satellite land cover has some very significant benefits. Satellite land cover allows the forecast to be easily extended beyond political boundaries. For a forecast within the City of Kelowna alone, current zoning maps could be used instead of satellite land cover maps; however, these zoning maps end at the edge of the political boundary. LoadSEER models require a buffer area of about 4 miles around the study area. This would be impossible if zoning maps are used. Also, zoning maps do not indicate if the land is developed or not. Certain parcels could be zoned as commercial, for example, but this growth may not occur for another few years or not at all. Again, satellite land cover allows the study area boundary to be extended to any region, regardless of political boundaries, while maintaining a consistent land use map.

5.4.1 Historic Satellite Imagery and Analysis

Historical land-use classification maps were established for prior years to consistently represent the study area's geography across time. Integral Analytics used three historical time periods of Landsat-5 satellite imagery, the minimum number recommended. While trending analysis is more robust as additional historical years are added, analyzing three time periods establishes two sets of simple linear trends. Integral Analytics uses segmentation and object-oriented processing to create the classification maps. Using the three historical land-use classification maps, advanced regression analytic techniques are applied to quantify the spatial land-use changes that historically have occurred within the study area across time and space.

Segmentation and object-oriented processing was used to create the final classification maps for 1990, 2000 and 2010.

(1) Image Acquisition: Acquire data through the United States Geological Survey.

(2) Preprocessing Algorithms: Standard radiometric correction and filtering algorithms.

(3) Geometric Correction: Correct the imagery for geometric errors and co-register to topographic maps.

(4) Image Enhancements and Data Transformations: Enhance the image mosaic using custom image enhancement algorithms specifically designed for this data to emphasize and distinguish between land-cover types.

(5) Land-Cover Classification: The classification will utilize a new technique in image processing developed by IA. This technique builds a custom classification for the Okanagan Region.

(6) Quality Assurance/Quality Control: Visually scan the classified maps for errors, and check with aerial photographs and high resolution imagery and correct for any classification errors identified.

The land-cover categories classified include:

- Rural Residential / Agriculture
- Low Density Residential
- Medium Density Residential
- High Density Residential
- Commercial
- Industrial
- Urban and Recreational Grasses (parks, golf courses etc.)
- Water
- Natural Vegetation (Forest)
- Transportation / Other (unusable categories)

5.5 Land Use Classification Methodology

The Current Land-Use Data includes a sufficient number of customer load classes to support the spatial load forecast process. Although the program design allows the user to define the classes he or she wants to model, LoadSEER must have a complete set of land-use categories covering all types of land-use in the study area. The model typically requires about twelve customer classes (three subcategories each of residential, commercial, and industrial, plus a few others) and a few more non-customer land uses like unusable land and water.

5.5.1 Load Classes

"Land use" refers to the use of land, by our society, for a purpose. We generally speak of different categories of land use as *land use classes*. Some land use classes are *utility customer classes*: residential, commercial, and industrial land uses, etc. These "developed" land use classes or customer classes produce electric demand and they are of primary interest to the utility and are the reason planners use rigorous forecasting computer models.

- **Residential Rural (0.58 kW/acre-** Rural housing in parcels with an area greater than three acres.

Figure 4 - Rural Area in Central Kelowna

Figure 5 - Rural Area Satellite Image of Central Kelowna

- **Low Density Residential (4.35 kW/acre)** – Single family home in parcels with area between one and three acres.

Figure 6 - Rural Area in North Central Kelowna

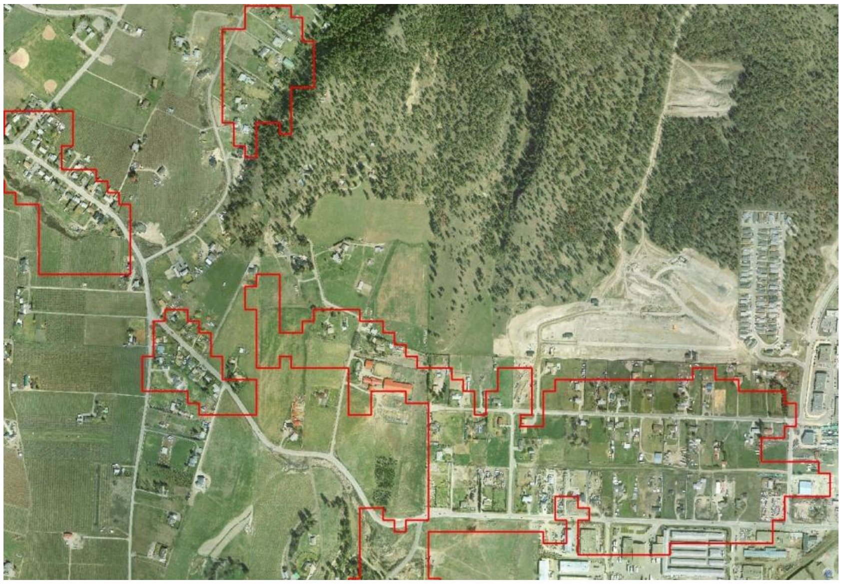

Figure 7 - Low Density Area Satellite Image of North Central Kelowna

- **Medium Density Residential (10.89 kW/acre)** – Single family home on lots with an area of less than one acre.

Figure 8 - Medium Density Area in Central Kelowna

Figure 9 - Medium Density Area Satellite Image of Central Kelowna

- **Residential High Density (16.82 kW/acre)** – Apartments, duplexes, condominiums, multi-family, town-houses.

Figure 10 - High Density Area in Downtown Kelowna

Figure 11 - High Density Area Satellite Image of Downtown Kelowna

- **Commercial Retail (27.48 kW/acre)** – Retail stores, shopping malls, strip malls, restaurants, schools, churches, higher education facilities, municipal and city facilities and office parks

Figure 12 - Commercial Area in Downtown Kelowna

Figure 13 - Commercial Area Satellite Image of Downtown

- **Industrial (22.8 kW/acre)** – Manufacturing and high-tech plants, industrial office parks, warehouse and some cross-over with the commercial class.

Figure 14 - Industrial Area in North Kelowna

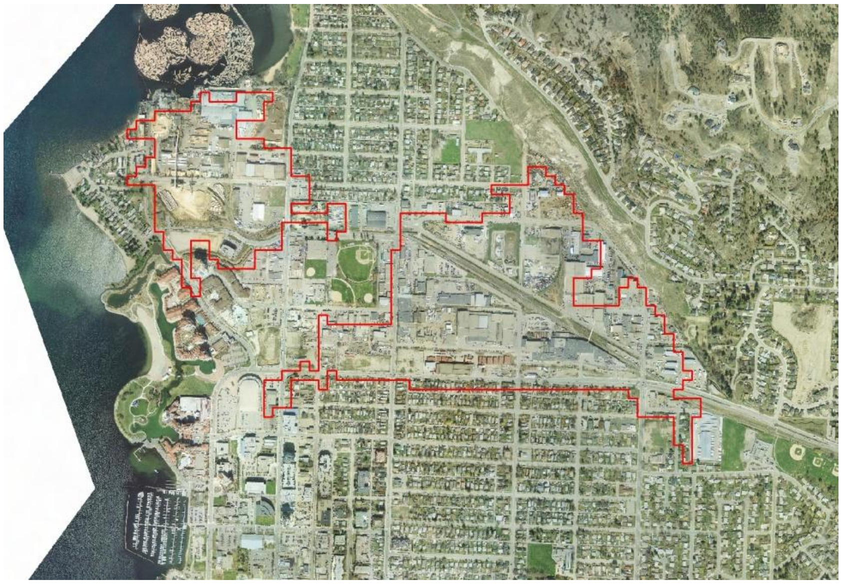

Figure 15 - Industrial Area Satellite Image of North Kelowna

5.5.2 Non-Load Classes

It is important to note that *modeled customer classes are a subset of land use classes.* But there are other land use classes relevant to spatial load forecasting, classes that are not developed and do not produce electric demand; therefore, are not customer classes, but are important to the forecast. They limit where development can occur or they attract development toward them (or push it away) or otherwise interact in an urban or rural environment to shape where, when and what development does take place.

- **Natural Vegetation and Forest**
- **Urban and Recreational Grasses**
- **Water**
- **Transportation**

5.6 Known Future Developments

Future known developments can be used as inputs to guide the spatial model. Information about these developments is gathered from developers, the City of Kelowna and FortisBC designers and planners.

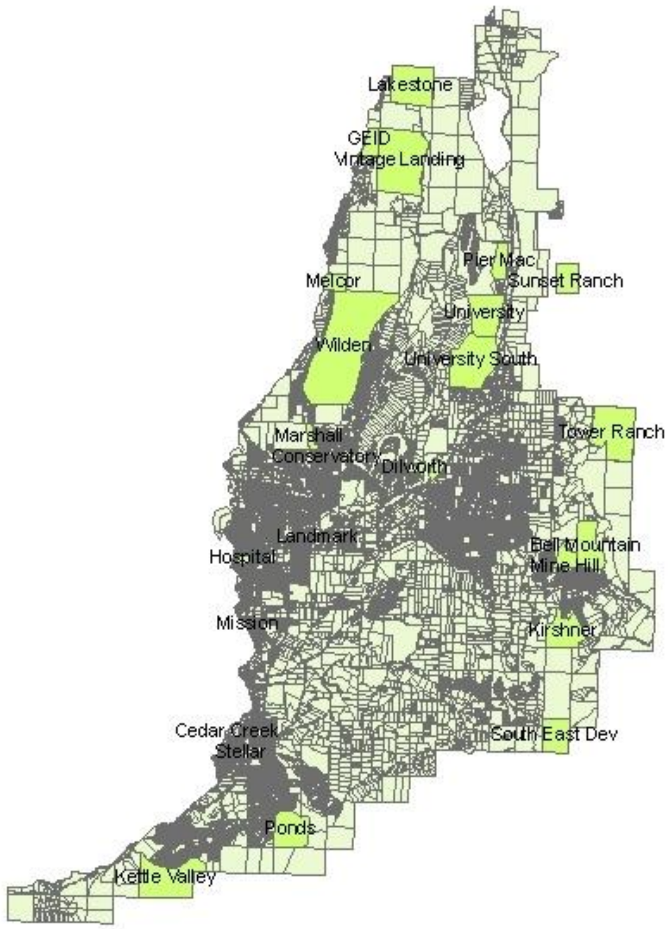

Figure 16 - known future developments in the Kelowna area

5.7 Load Profile

Each customer class requires a unique load profile. This describes how they use energy and what time the peak demand occurs. Typically, the load profile is described by a 24 hour load shape. This load curve is ideally determined from 8760 hour weather normalized data for each particular class.

Since no load research data is available for the Kelowna region explicitly giving the load curve profile for each customer class, each curve was inferred from 15-minute feeder data. This involved three steps:

1. Determining the coincident weather normalized peak for every feeder with hourly load and weather data
2. Finding the load density per acre for each class by minimizing root mean square error
3. Applying the per acre load density to a load curve for each class

5.7.1 Determining the Coincident Weather Normalized Peak

The coincident weather normalized peak was determined from one year of hourly feeder data from 2009. The following six steps were performed by Quanta Technology experts:

1. Normalize the weather. This requires the available hourly temperature data and the average temperature for each hour of the year.
2. Build a multiple linear regression model to capture the relationship between load and temperature and calendar variables. The format is: Load = intercept + b1*trend + b2*temperature + …
3. Plug in the average temperature to the model above, to come up with the system level normalized load for each hour.
4. Calculate the normalization coefficient for each hour (normalization coefficient = predicted load / actual load).
5. Multiply this coefficient with the actual feeder load to get the normalized feeder load for each hour.
6. Finally pick up the peak hour for each feeder.

5.7.2 Determining the Load Density per Acre by Class

In the Kelowna area, only 15 minute feeder data is available; no direct customer class data has been sufficiently recorded. To infer the customer class load profile, an excel solver is used by aggregating the per customer load across each feeder or substation and minimizing the root mean square.

To start, one year of feeder data is weather normalized and the peaks are determined. Next, feeder circuit polygons are overlaid on the land cover map. The ArcGIS Spatial Analyst "Tabulate Area" tool is used to calculate the number of acres of each class in each feeder.

Finally, the feeder peaks and number of acres for each feeder is put into a spreadsheet to calculate the load per acre for each class.

Table 3 - Weather normalized 4pm summer coincident peak load by class per acre

Class	2010 Peak Load (kVA)
Industrial	22.81
Commercial	27.48
High Residential	16.83
Medium Residential	10.88
Low Residential	4.3546
Agriculture	0.58

5.7.3 Determining the Load Profile

The coincident peak at 4pm is determined by the overall system composition of the various customer types. However, certain feeders with predominately residential customers may have a higher peak around 6pm or 7pm; feeders with mostly commercial customers may peak during the afternoon coffee break around 2pm or 3pm and so on. Therefore, it is necessary to apply a load profile to the coincident peak to account for individual feeder peaks.

To do this, normalized load curves were created for each class. These load curve shapes where inferred from feeder 15-minute data as shown below. For each class, a feeder was selected that had the highest percentage of connected transformer capacity on a particular class. For example, about 86% of the connected transformer capacity for the OKM3 feeder is located on residential property. Therefore, it makes sense that the overall OKM3 load curve shape will represent the residential class.

The actual normalized load curve profile was calculated by averaging one year of 15 minute feeder data and normalizing it to the 4pm peak load.

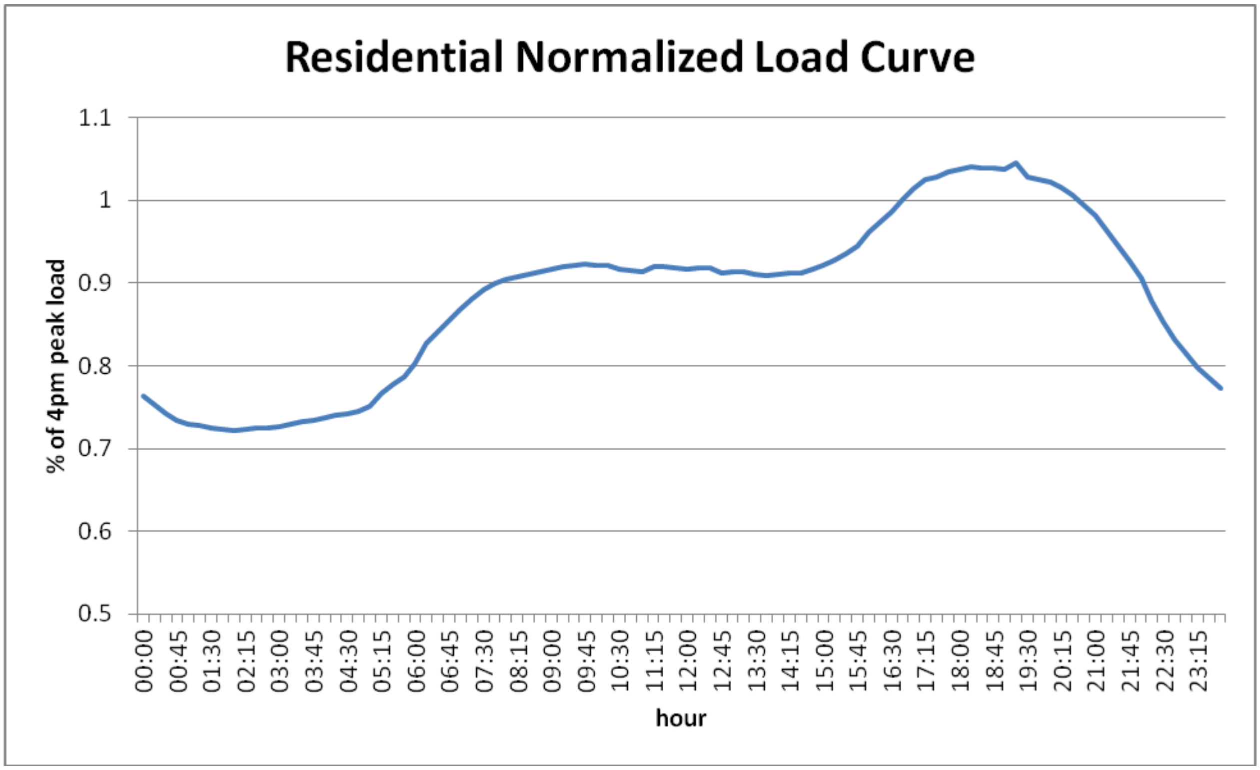

Figure 17 - 4pm normalized residential load curve created from the average 2009 hourly load on the OKM3 feeder (86% of the feeder is residential)

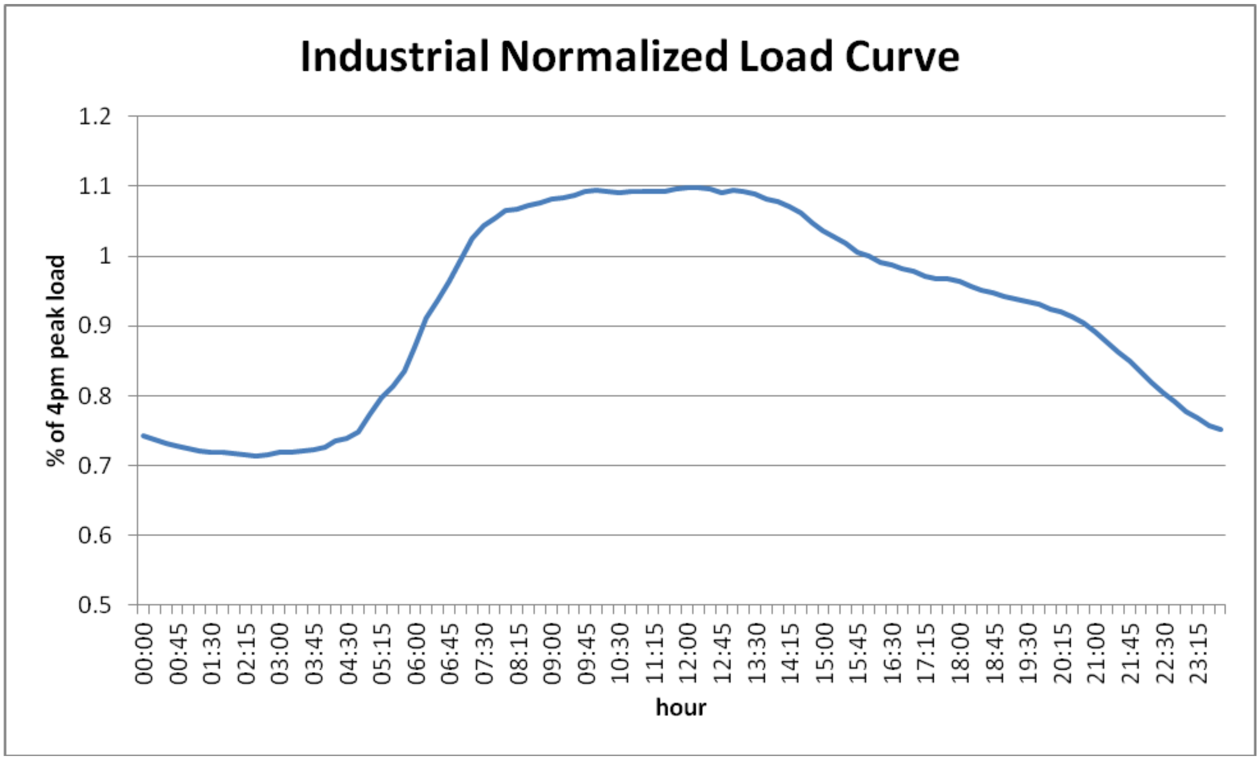

Figure 18 - Industrial load curve from SEX1 feeder (73% of the feeder is industrial) normalized to the 4pm peak value

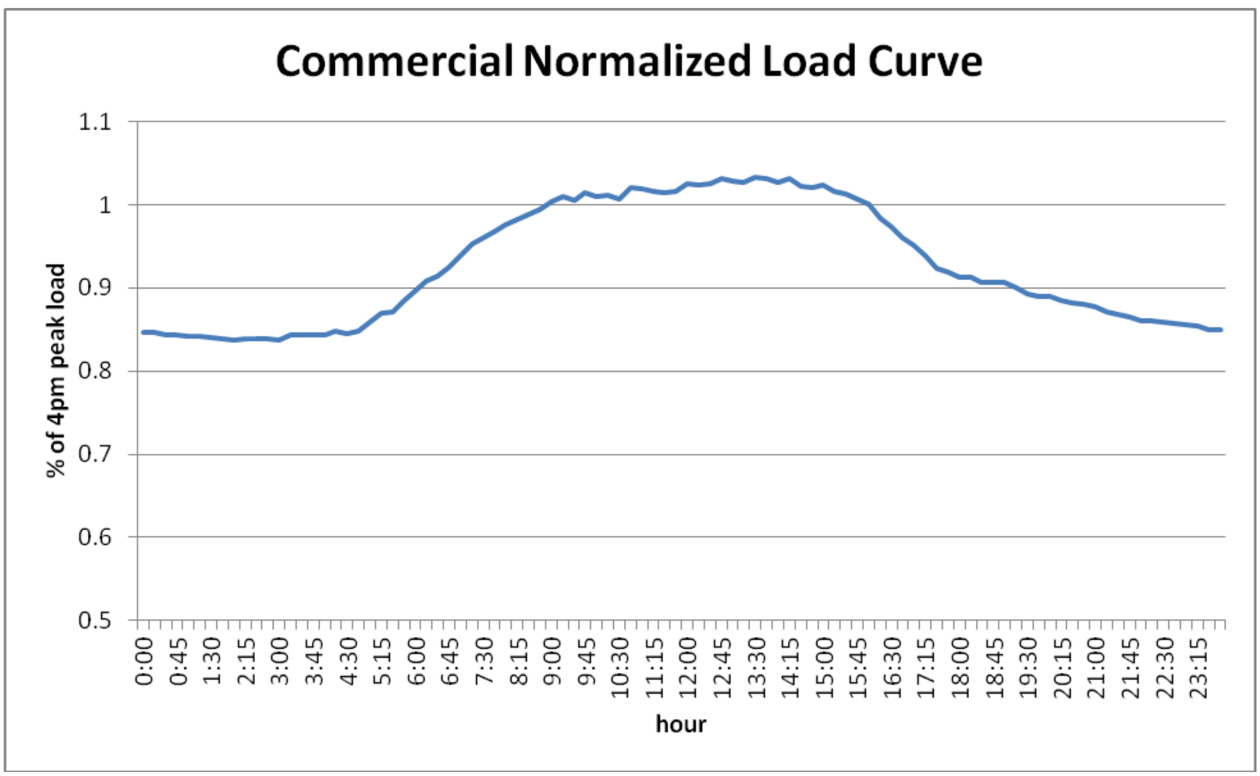

Figure 18 - Commercial load curve from GLE3 feeder (90% of the feeder is Commercial) normalized to the 4pm peak value

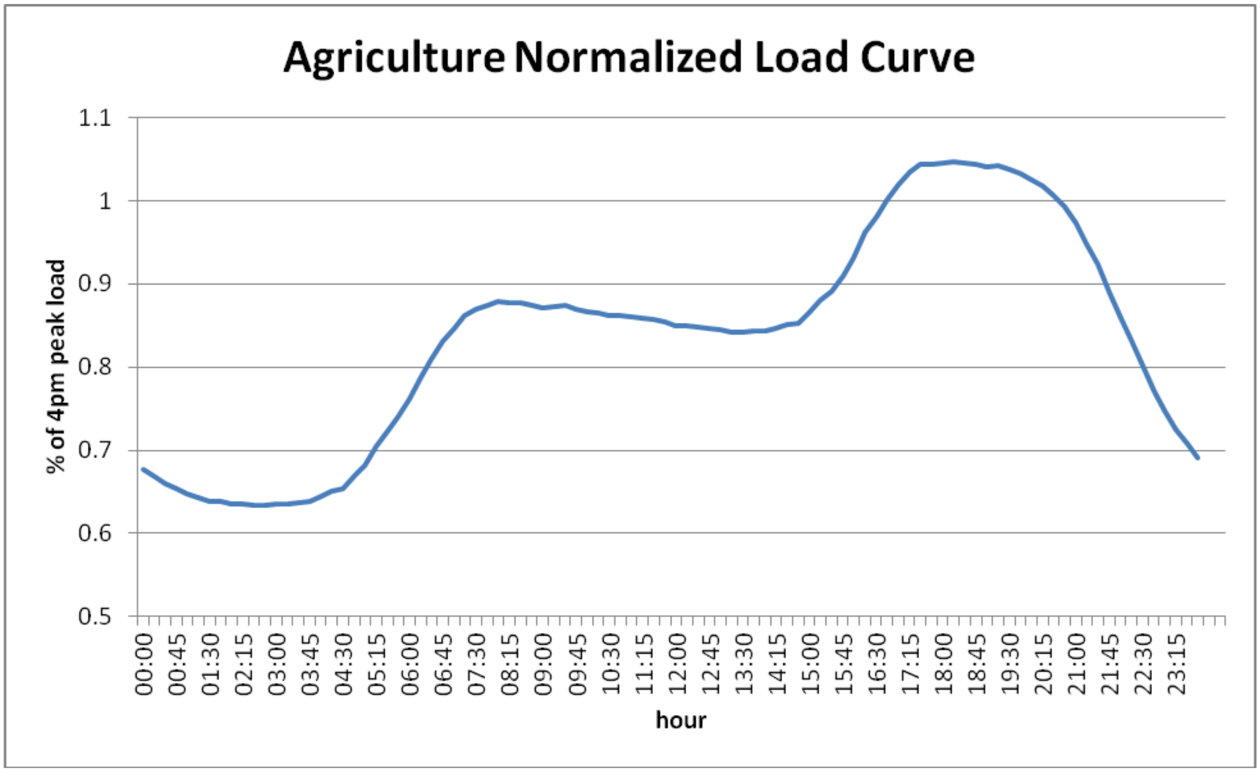

Figure 19 - Agriculture load curve from DGB3 feeder (73% of the feeder is Agricultural) normalized to the 4pm peak value

5.8 Forecast Growth Rate

The growth rates for the spatial load forecast are obtained from the FortisBC corporate forecast. Population growth statistics and forecasts for the Kelowna area are used to infer how the Kelowna growth rates relate to the corporate system level growth rates.

Table 2 – Forecast Growth Rates 2010 to 2030

	2010	2011	2013	2016	2020	2025	2030
Commercial	1.5%	1.5%	2.8%	4%	5%	5.6%	4.8%
Industrial	1.5%	1.5%	2.8%	4%	5%	5.6%	4.8%
Single Family Low Residential	1.5%	1.5%	2.8%	4%	5%	5.6%	4.8%
Single Family Medium Residential	1.5%	1.5%	2.8%	4%	5%	5.6%	4.8%
Single Family High Residential	1.5%	1.5%	2.8%	4%	5%	5.6%	4.8%

Based on available data and for simplicity, growth rates for all classes were assumed to be the same. Future analysis could be done to determine more accurate growth rates for each individual class.

5.9 Spatial Load Forecast

For the analysis, there are three categories of models. The first is referred to as a "deterministic" model, the second is labelled a "statistical" model, and the third is a combination of the two. The deterministic model means that factors outside of pure historical growth patterns were used as inputs to the model. For example, using the Kelowna Official Community Plan Future Land Use map makes the model deterministic because this type of data input comes from urban planner's idea of future growth and is not based purely on historical growth trends. The statistical model, on the other hand, is totally dependent on historic patterns. It is developed from regression of historic land use maps. The hybrid combination of the two take the statistical model results and adds constraints and regional factors such as ALR classification, urban poles and proximity/surround factors.

5.9.1 Base Scenario I: Fully Deterministic Based on OCP 2020 and Raw Developments (as regional factor)

This model is a very high quality deterministic model. It uses all the best knowledge of the FortisBC designers, planners, and Primary Engineering experts to add information about known future developments. These raw developments are used to encourage development of certain classes in specified areas; the raw developments are not forced, however, to grow as expected.

5.9.1.1 Input Factors

The input factors consisted of base year land use (section 5.4), transportation data, regional influence factorsand urban poles.

The base year land use data was provided by satellite imagery from Integral Analytics (Figure 38). The transportation data was provided by ESRI. The future land use data came from the City of Kelowna OCP map (section 5.3.2). An ALR map was included as a regional factor to discourage growth in ALR areas (section 5.3.1). Elevation and slope was used to discourage growth in undevelopable areas, such as on the edge of a cliff. In this model, the known developments were included as a regional factor to encourage growth to occur in areas specified by designers and planners (section 5.5.2).

Abbreviations:

- com = commercial class
- ind = industrial class
- high res = high density residential
- med res = medium density residential
- low res = low density residential

Integral Analytics

Primary Engineering and Construction

5.9.1.2 Preference Matrix and Maps

Table 3 – Regional Factors Affecting Class Growth

Regional Factor	com.	ind.	high res.	med. res.	low res.
Known Developments: Commercial	2	0	2	1	2
Known Developments: Industrial	0	2	0	0	0
Known Developments: Residential	1	1	1	2	1
Future Land Use: Commercial	2	0	0	0	0
Future Land Use: First Nations Reserve	-1	-1	-1	-1	-1
Future Land Use: Future Urban Reserve	1	1	1	1	1
Future Land Use: Industrial	0	2	0	0	0
Future Land Use: Multi Family Residential (cluster)	0	0	1	1	0
Future Land Use: Multi Family Residential (high)	0	0	1	1	0
Future Land Use: Multi Family Residential (low)	0	0	0	0	2
Future Land Use: Multi Family Residential (medium)	0	0	0	2	0
Future Land Use: Park	-2	-2	-2	-2	-2
Future Land Use: Single Family Residential	0	0	1	1	0
Urban Pole (downtown) – 15miles	2	2	1	0	1
Urban Pole (Glenmore) – 5 miles	1	1	1	1	1
Urban Pole (Mission) – 5 miles	1	0	1	1	1
Urban Pole (Rutland) – 5 miles	1	0	1	1	1
Urban Pole (University) – 5 miles	2	0	2	0	1
Elevation	0	-1	1	0.5	0
Slope	-1	-1	-1	-1	-1
ALR	-2	-2	-2	-2	-2

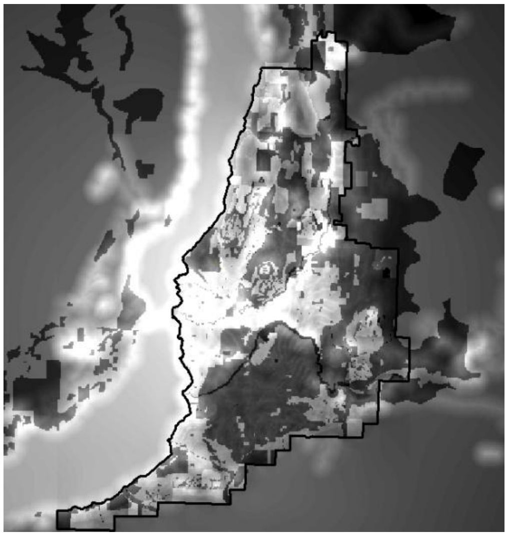

Figure 20 - Commercial preference map

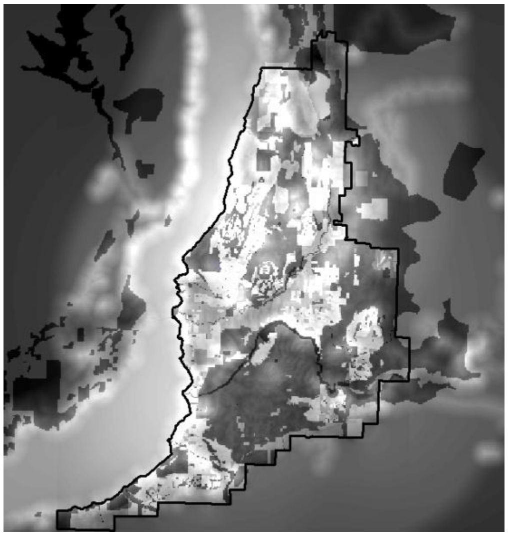

Figure 21 - Single family high residential preference map

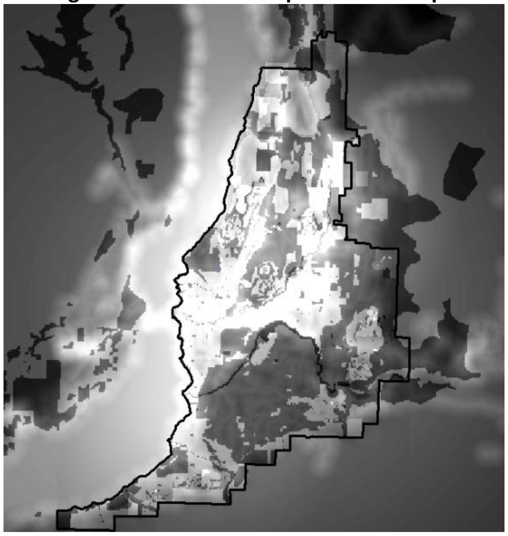

Figure 22 - Industrial preference map

Figure 23 - Single family low residential preference map

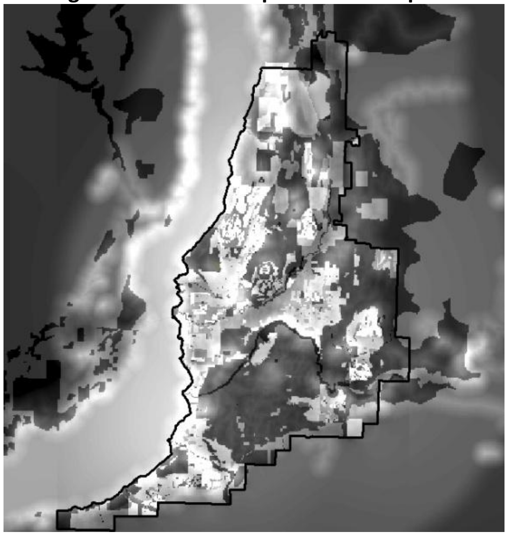

Figure 24 - Single family medium residential preference map

5.9.1.3 Proximity and Surround Matrix Maps

The proximity and surround factors for this deterministic model were selected primarily based on intuition and local knowledge of the area. A distance of 0.5 miles for all factors was selected for simplicity.

Table4 – Proximity Factors

Proximity Factor	com.	ind.	high res.	med. res.	low res.
Local Road (0.5 miles)	1	1	1	1	1
Secondary Highway (0.5 miles)	1	1	1	1	0
Primary Highway (0.5 miles)	1	1	0	0	0
Ramp (0.5 miles)	1	1	0	0	0
Water (0.5 miles)	2	2	2	2	2
Public Utilities Service (0.5 miles)	-1	-1	-1	-1	-1
Airport (0.5 miles)	1	1	1	0	0

Table5 – Surround Factors

Surround Factor	com.	ind.	high res.	med. res.	low res.
Water (0.5 miles)	1	0	1	1	1
Industrial (0.5 miles)	0	2	-1	-1	-1
Commercial (0.5 miles)	1	0	0	0	0
Urban Grasses/Parks/etc. (0.5 miles)	1	0	2	2	1
Available land (0.5 miles)	0	0	1	1	1

The following figures show how these proximity and surround factors are represented spatially.

Figure 25 - Proximity to available land

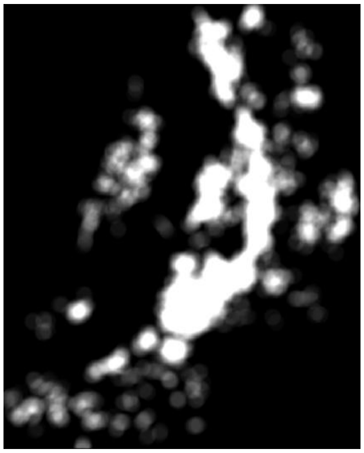

Figure 26 - Available Land Surround Map

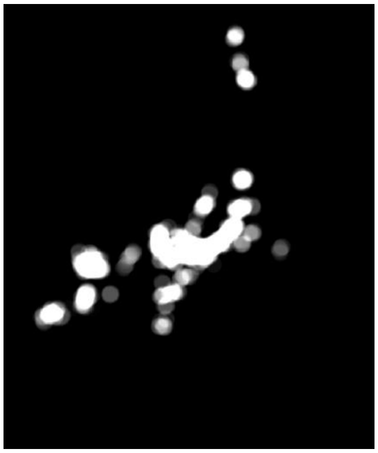

Figure 27 - Commercial Surround Map

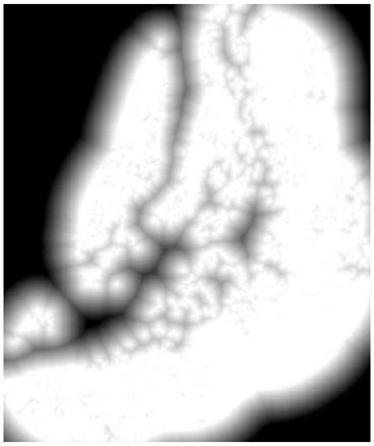

Figure 28 - Natural Vegetation and Forest Surround Map

Figure 29 - Proximity to Secondary Highway

Figure 30 - Proximity to Local Roads

Figure 31 - Proximity to Primary Highway

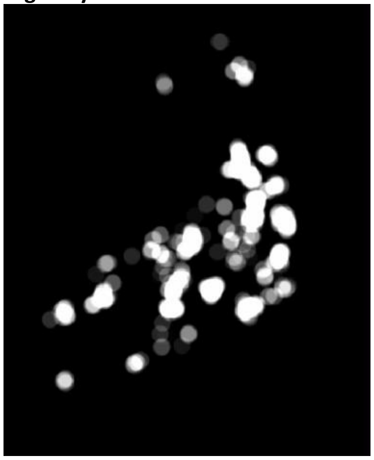

Figure 32 - Urban Grasses and Parks Surround Map

Figure 33 - Proximity to Water

5.9.1.4 Model Land Use Spatial Results

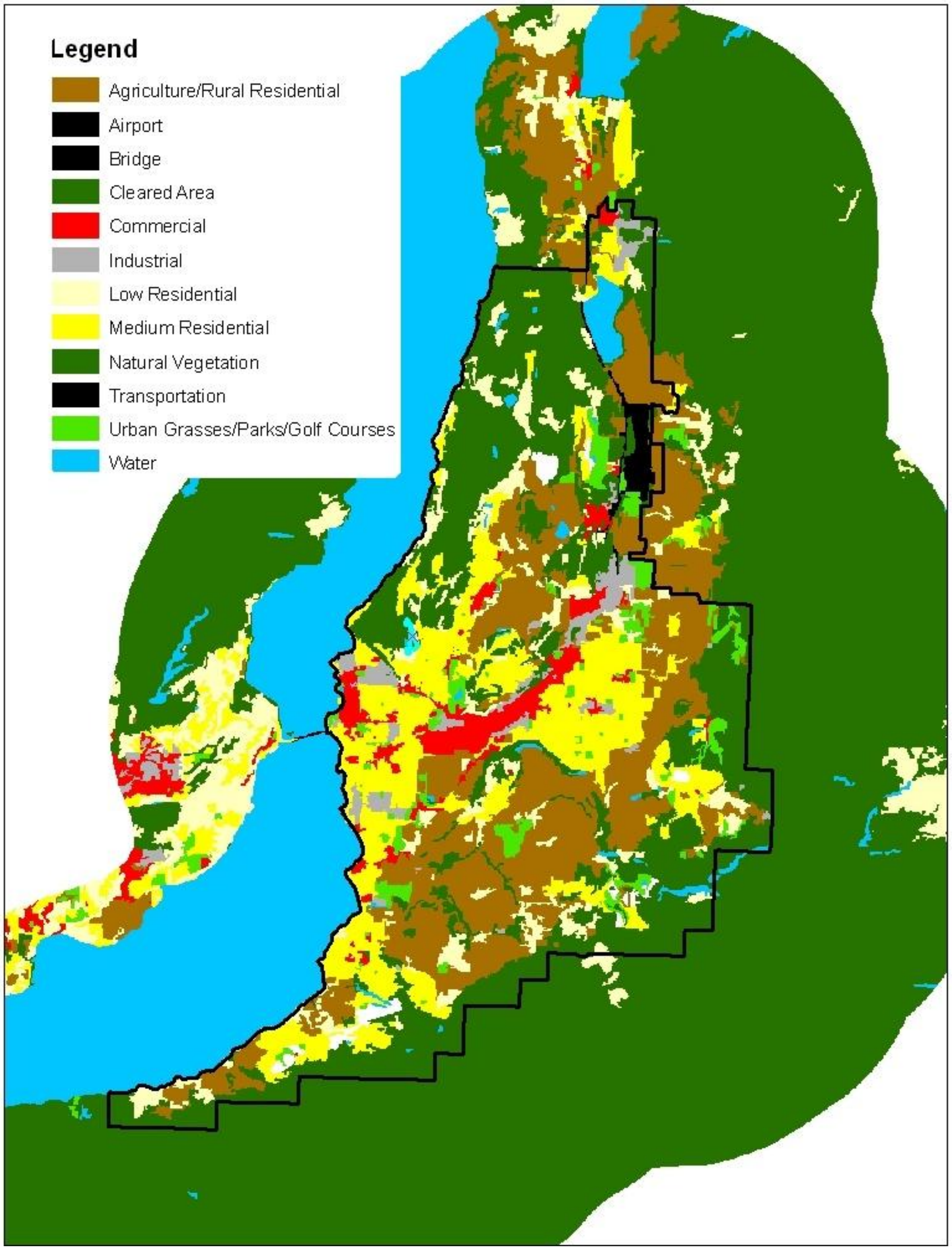

Figure 34 – 2011 Deterministic Model I Land Use Forecast results

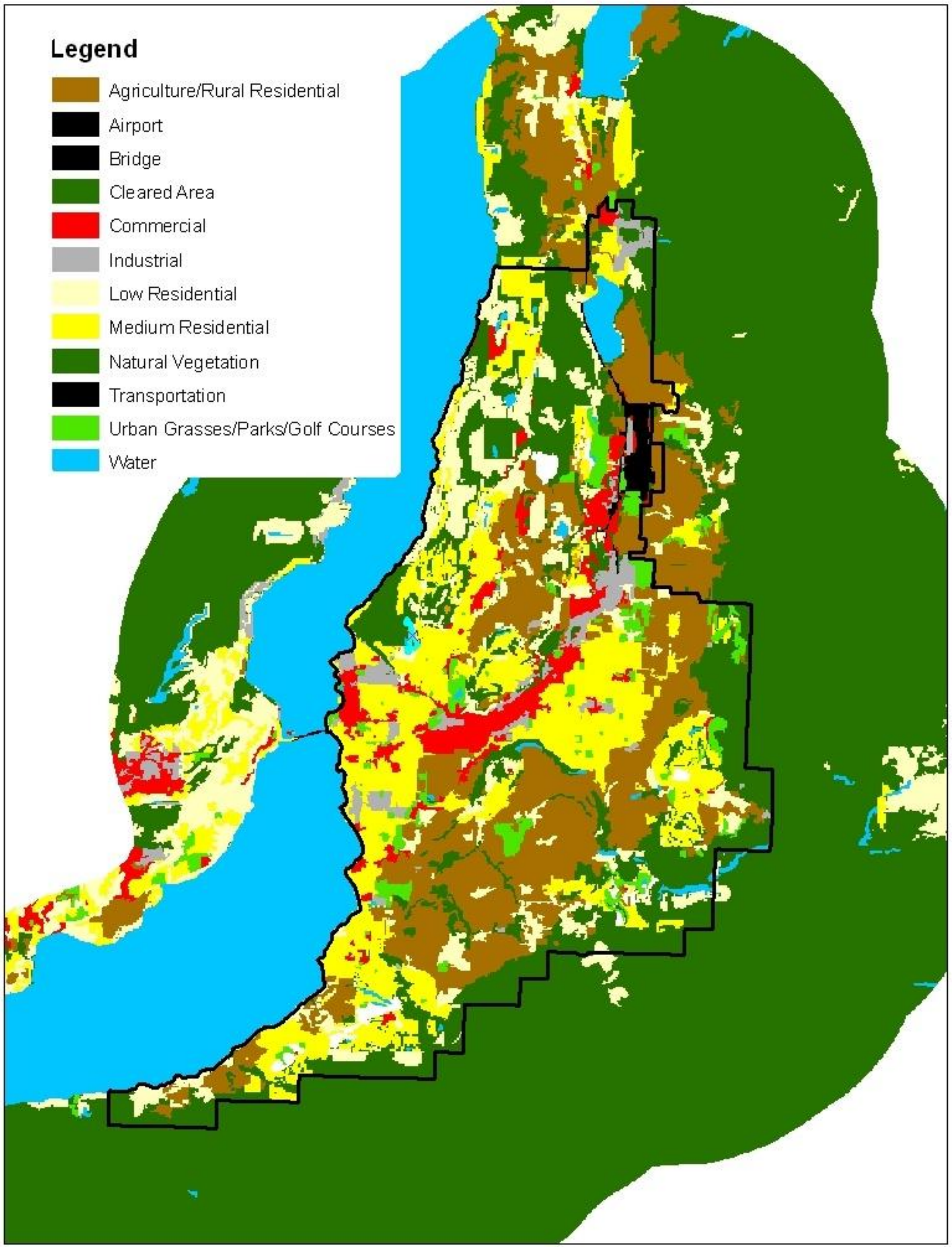

Figure 35 - 2030 Deterministic Model I Land Use Forecast results

6 Project Deliverables

The following items are the deliverables of the spatial electric forecasting project:

- Land cover satellite imagery of the Kelowna area for 1990, 2000, and 2010
- Weather normalization of substation and feeders for the Kelowna area using available data
- Two days of training by Integral Analytics on using the LoadSEER software
- Fully deterministic base models including the model setup files, run files and spatial results
- Fully statistical base model created from statistical regression on the historic satellite maps
- Model setup files, results database files, database documentation of inputsand spatial results for each base model
- Feeder-by-feeder forecast results from 2010 to 2030
- A report that fully documents the background and details around the forecasting
- Digital compilation of related forecasting tools, documentation, graphics, literatureand results
- Create more scenarios from the base model.
- Calculate weather normalized loads for extreme weather
- Develop load forecast for each feeder including weather normalization which can be compared to the linear load forecast for Kelowna.

6.1 Next Steps and Possible Future Enhancements

The primary goal of spatial electric load forecasting is to improve transmission and distribution planning and subsequently obtain maximum returns on capital investments. Spatial electric load forecasting efforts can be further enhanced and developed to obtain increasingly better results and planning insight. Below are some areas that the load forecast should be expanded in the future:

- Add a substation trend to guide the model to enhance the short term forecast
- Add Big White and Joe Rich substations to this forecast and identify overall North Okanagan results
- Brief analysis of near future distribution projects that can be improved by the spatial forecasting project results
- Expand forecasting area to the entire FortisBC region
- More detailed feeder and substation regression trending to guide the model
- Determine better growth rates on a per class basis. Currently, a ball-park growth rate was used across all customer classes. This growth rate was based on regression of historic population statistics for the Kelowna area. These growth rates are reasonable for residential growth; however, it may not be valid to assume and commercial and industrial growth rates are similar. Therefore, it would be beneficial to perform another analysis to determine better growth rates for non-residential classes.
- Create scenarios to assess the impact of baby-boomer retirement within the Okanagan. The current forecasted growth rates use regression to determine future growth rates. But, what if there is a significant surge in retirees moving to the Okanagan area within the next 5 or 10 years? What areas would these people likely move to? What would be the impact on the grid?
- Expand on the land use classification. For this forecast, classes included Natural Vegetation, Agriculture, Cleared Land, Low Density Single Family Residential, Medium Density Single Family Residential, High Density Single Family Residential, Commercial, Industrial and Public Utility. In the

future, it would be beneficial to add classes for multi-family residential and classes to distinguish between different types of industrial and commercial. The most significant challenge to this is updating the satellite land use maps and determining load curve profiles for each class.

- Create scenarios to account for development on existing used land (for example, a single family home demolished to install a commercial building)
- How might electric vehicles impact the Kelowna area electric demand? Adoption of electric vehicles may not be a significant percentage; however, the people who do adopt electric vehicles are likely to be clustered in certain areas. What neighbourhoods are likely to adopt first? Can the distribution system meet these needs? How could DSM or other initiatives be implemented to make strategic investments?
- More regional factors could be added to the forecast such as soil data and the location of K-12 schools. Soil data in particular could be used to enhance the modeling of growth within the ALR land.
- For this forecast, satellite maps from 1990, 2000 and 2010 were used. Adding more historical satellite maps would improve land use trending.

7 Conclusion

A set of base spatial electric load forecasts have been completed for the Kelowna area. The overall project has been a success:

- This the first truly spatial electric forecast to be completed at FortisBC
- While these advanced spatial tools and methodologies have been tested and thoroughly used in several American utilities, FortisBC is one of the first Canadian utility to capitalize on these powerful spatial tools to assist forecasting and planning efforts.
- The project was guided by one of the world's foremost experts in spatial electric forecasting, Lee Willis. It additionally utilized the world class expertise of Integral Analytics and Quanta Technology.
- Four months after the initial project conception a base forecast is fully ready. In May 2010, FortisBC had an idea that spatial forecasting would assist corporate and engineering objectives. At that time, the concept of "spatial" forecasting was new. The possible methodologies, tools, software and requirements were unknown.

Primary Engineering would like to thank FortisBC for the opportunity to develop this spatial electric load forecast and ultimately serve their customers.

8 Acknowledgements

This spatial electric load forecasting project would not be possible without the support and expertise of numerous individuals. The following people are recognized for their contributions to this project.

Lee Willis, Quanta Technology, has over 35 years of experience in spatial electric load forecasting. He provided expert oversight and advice throughout the project.

Troy Martin, Primary Engineering, with 20 years of distribution experience, gave much insight to growth trends and engineering planning needs for the Kelowna area. He also gave oversight to the entire project.

Scott Smith and his support team form Integral Analytics was a significant asset to the project. They developed the LoadSEER software, provided satellite imagery and software training.

Lindsay Leschiutta, Primary Engineering, prepared GIS substation and feeder data, ran model simulations and supported other GIS tasks.

Jason Hart, FortisBC, provided automation of feeder polygons and ArcGIS Spatial Analyst software setup.

Rod Allin, City of Kelowna, provided information about the City of Kelowna GIS data.

Martin Ward, FortisBC, was the project manager and coordinated details from FortisBC.

Paul Chernikhowsky, FortisBC, is the project owner. He initiated and supported the spatial load forecasting project.

Marlin Frederick, FortisBC, provided information about the ION Enterprise system and supported the feeder data extraction.

Shelley Fizor, FortisBC, performed the data extraction from the ION database.

Tao Hong, Quanta Technology, performed the weather normalization of the feeder and substation data.

Sandra Gault, FortisBC, provided corporate forecast and growth rates to guide the forecast and maintain consistency.

Gary Williams, FortisBC, provided information about the Kelowna region and insight about future growth.

FortisBC designers Corey Linderman and Hugh Barbour provided insight about known developments.

Devin Krenz, FortisBC, gave insight into the FortisBC planning criteria, planning engineering needs, information about the existing forecast methodology, details about the Kelowna region, and supported the collection of data inputs.

Brain Underhill, Agricultural Land Commission, provided insight regarding the potential influence of the ALR on future development and growth.

Michael Sidiropoulos, FortisBC, provided insight about the FortisBC planning process and collaborated to ensure consistency between the distribution and corporate forecasts.

9 References

Willis, H. Lee (2002a). Power distribution planning reference book. Raleigh, North Carolina, U.S.A.: CRC Press.

Willis, H. Lee (2002b). Spatial electric load forecasting. Raleigh, North Carolina, U.S.A.: CRC Press.

10 Appendix: Historic Satellite Imagery (1990, 2000, 2010)

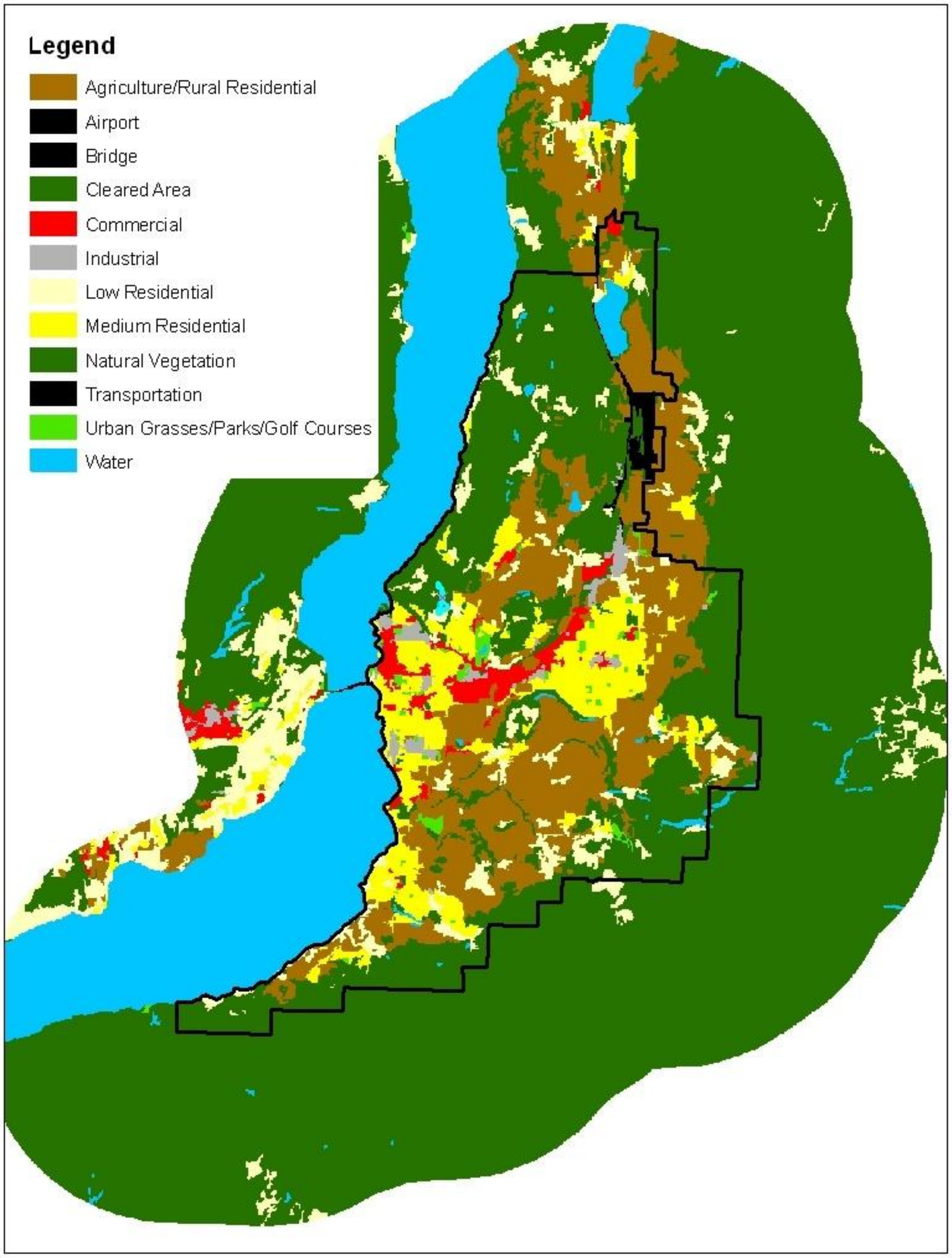

Figure 36 - 1990 land cover from satellite imagery analysis

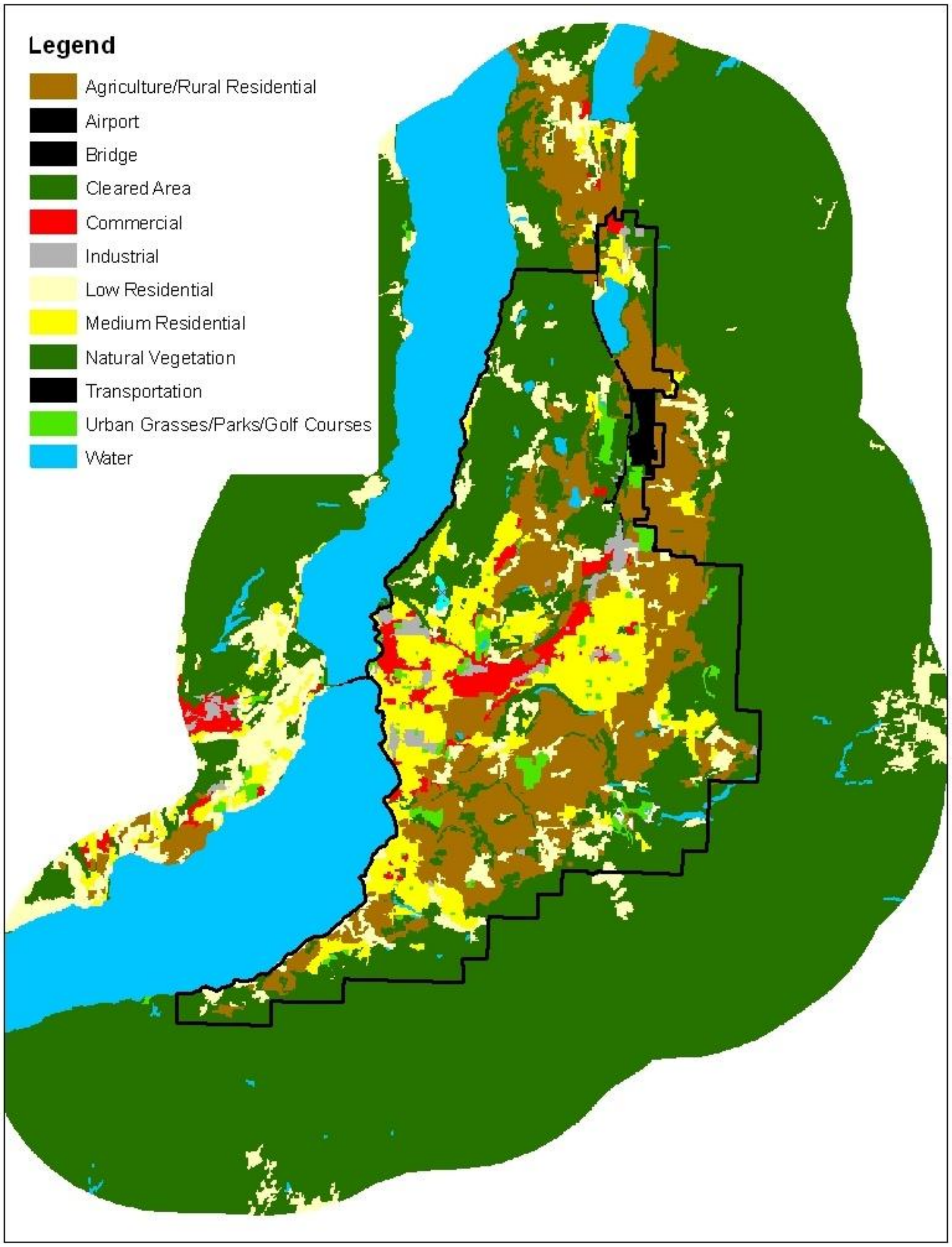

Figure 37 - 2000 land cover from satellite imagery analysis

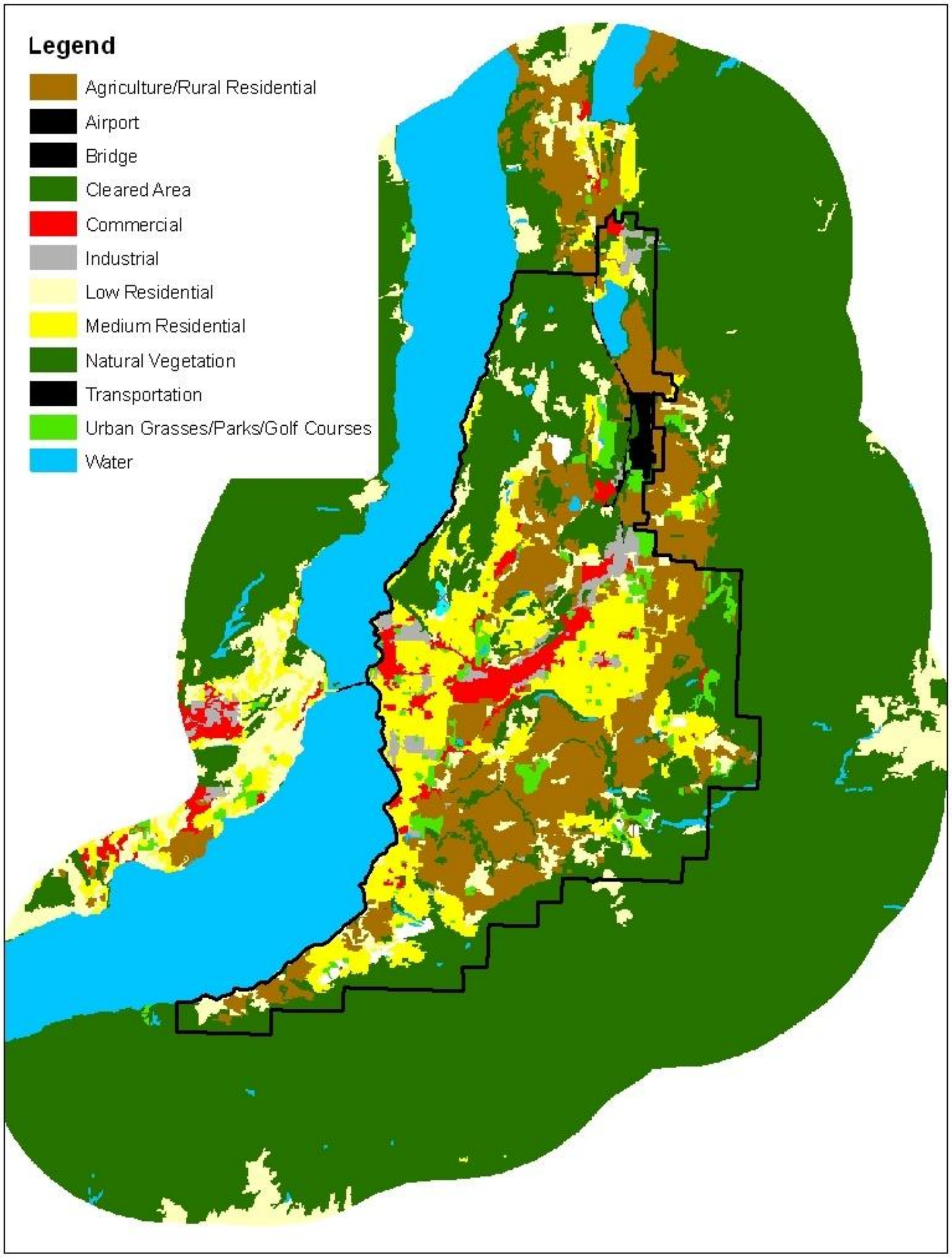

Figure 38 - 2010 land cover from satellite imagery analysis

11 Appendix: ALR in the City of Kelowna

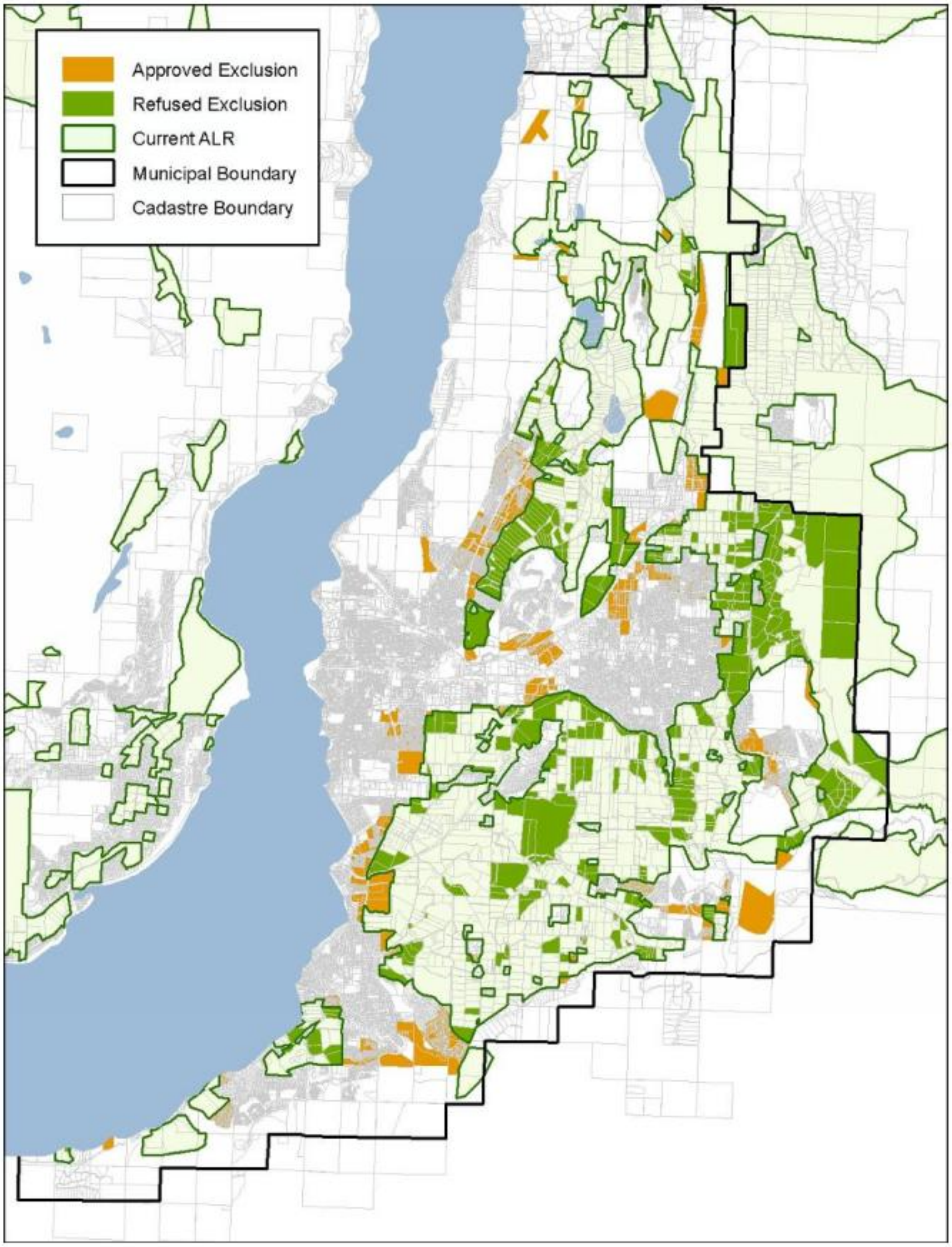

Figure 39 - ALR parcels with exclusion applications within the City of Kelowna. Source: Ministry of Agriculture and Lands (2008). Refer to Appendix15: ALR Report.

12 Appendix: City of Kelowna Future Land Use Map

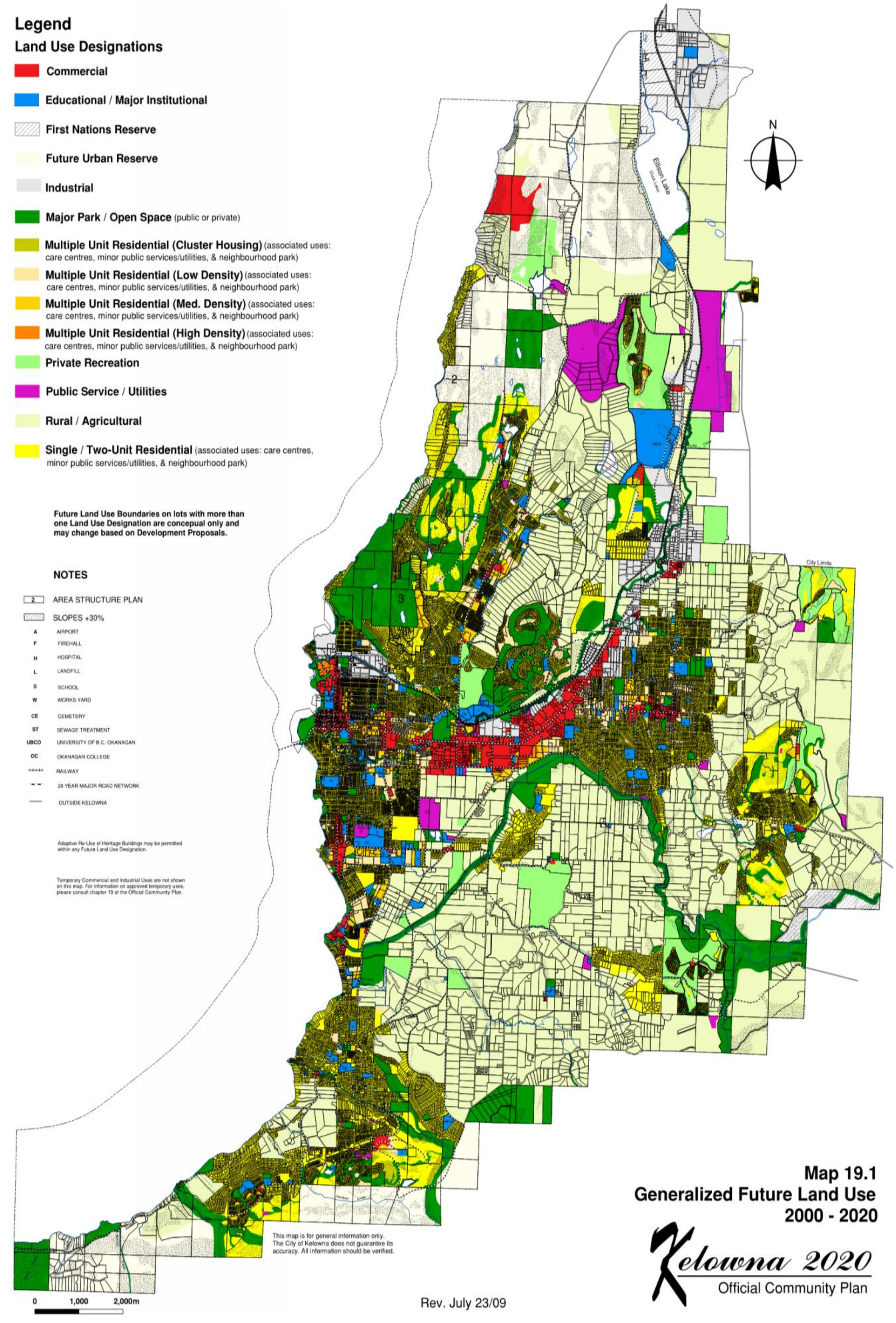

Figure 40 - City of Kelowna Future Land Use Maps from the 2020 Official Community Plan.

13 Appendix: Kelowna Transportation Map

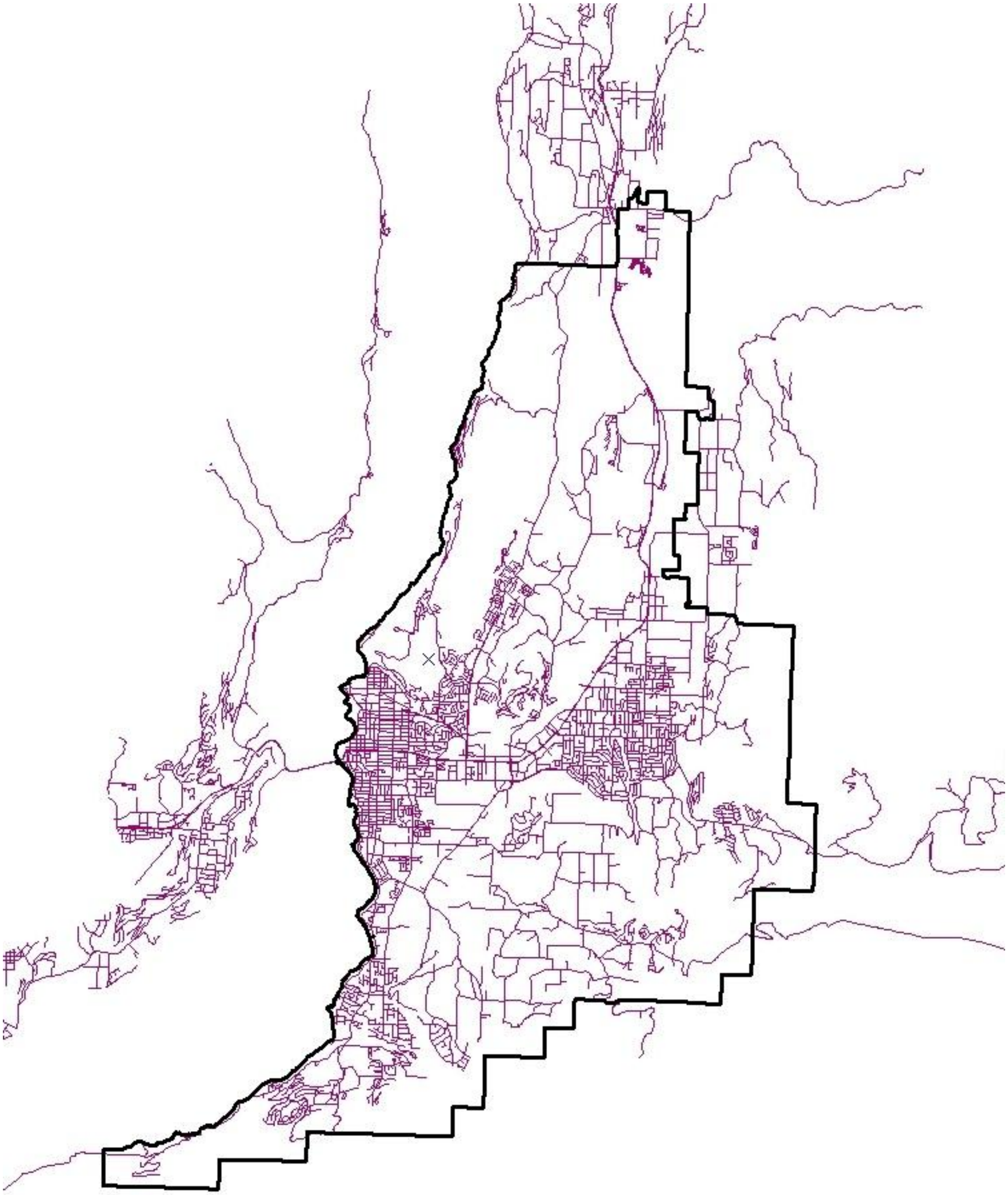

Figure 41 - City of Kelowna Transportation Map from the 2020 Official Community Plan.

14 Appendix D: Report "The Agricultural Land Reserve and its Influence on Agriculture in the City of Kelowna"

Growing Knowledge

British Columbia
The Best Place on Earth

Ministry of Agriculture and Lands

Strengthening Farming Report

File Number 800.100-3 May 2008

The Agricultural Land Reserve and its Influence on Agriculture in the City of Kelowna

A Review from 1973 to 2006

Ministry of Agriculture and Lands
and
Agricultural Land Commission

British Columbia
The Best Place on Earth

ALC

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The ALR and its Influence on Agriculture in the City of Kelowna

1. BACKGROUND

The Agricultural Land Reserve (ALR) is a provincial land use zone designated in 1973 to preserve agricultural land for farming. With a total area of 4.7 million hectares, the ALR covers approximately 5% of British Columbia's land base[1] and is comprised of both private and Crown lands.

The Agricultural Land Commission (ALC) is the provincial agency responsible for administering the ALR. The purpose of the Commission is to:

1. preserve agricultural land;
2. encourage farming on agricultural land in collaboration with other communities of interest;
3. encourage local governments, First Nations, provincial government and its agencies to enable and accommodate farm use of agricultural land and uses compatible with agriculture in their plans, bylaws and policies.[2]

The ALC makes decisions on applications to include or exclude agricultural land from the ALR. It also controls non-farm uses and subdivision within the ALR. As an independent administrative tribunal, the Commission considers all information relevant to each application and weighs the likely impact of the proposal against the long-term goal of preserving agricultural land and encouraging farming. The type of information considered includes: agricultural capability, suitability, current land use, the property in relation to surrounding lands, related agricultural concerns, and community planning objectives. Finally, the picture is broadened further to consider the provincial interest of preservation of agricultural land for British Columbia.

Agriculture is BC's third largest primary industry, generating $2.4 billion annually in farm cash receipts and providing for approximately half of BC's food requirements[3]. Without the ALR, the extent and diversity of this important economic sector would be at risk and much of the agricultural lands that exist today would likely have been lost to encroaching urban development. The ALR, thus, provides a secondary benefit in that it serves as an urban containment boundary, helping to control urban sprawl.

By maintaining the ALR boundary and by regulating non-farm uses and subdivisions within its boundaries, the Agricultural Land Commission plays a key role in preserving farmland for agricultural development and enabling future agricultural expansion throughout British Columbia. Providing a stable land base ultimately leads to increased food security for the province's rising population.

2. STUDY PURPOSE

The ALC and the Ministry of Agriculture and Lands (MAL) undertook this study to understand the impacts of the ALR with regard to its influence on agricultural land use in the City of Kelowna. Since the ALR was established over 34 years ago, it is useful to examine how agriculture has been shaped by the ALR and to illustrate its effectiveness in protecting farmland and sustaining the agriculture sector.

To meet the purpose of the study, all ALR exclusion applications in the study area (Section 3) were reviewed and digitally mapped to reveal what the agricultural landscape may have looked like if all exclusion applications had been allowed. Inclusion applications were also reviewed, but were not included in the analysis as there were only two approved inclusions in the City of Kelowna between 1973 and 2006, totaling less than one hectare.

[1] Provincial Agricultural Land Commission, Application Information Package, 2003.
[2] Agricultural Land Commission Act, S.B.C. 2002, c.3.
[3] B.C. Ministry of Agriculture and Lands, Fast Stats: Agriculture and Food (2005).

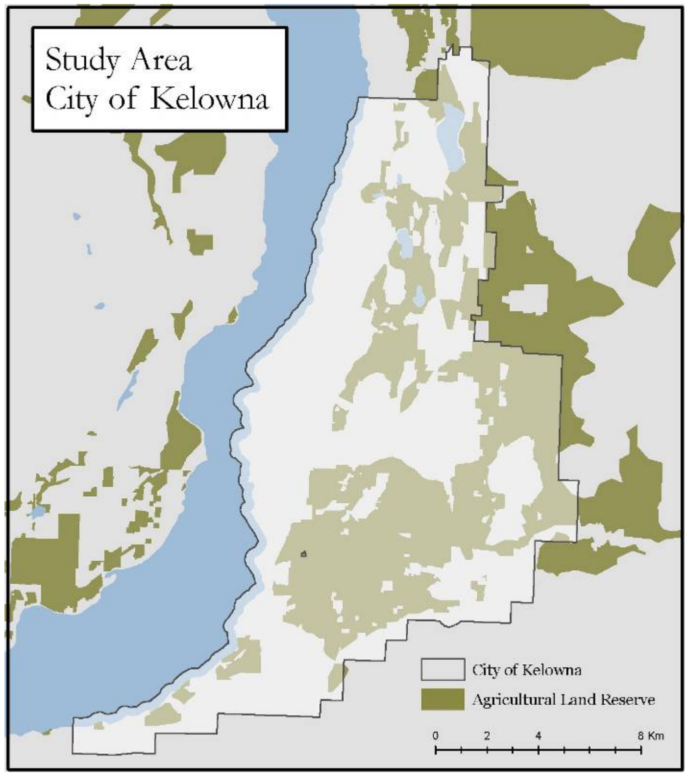
This exercise will illustrate in simple terms what the extent of agriculture in Kelowna would possibly be today, had the ALR not existed. Although the presence of the ALR is not the only determining factor in influencing current agricultural activity levels, for purposes of this study, it is assumed that the ALR plays a significant role, as access to a stable land base reserved for agriculture is a key factor.

3. STUDY AREA

Study area (Map 1) because it has a vibrant agriculture industry that is appreciated in particular for its strong tree fruit and wine industries. The City of Kelowna has experienced significant pressure from urban development and, as a result, has had 188 applications to remove land from the ALR since 1973.

The jurisdictional land area of Kelowna is 21,656 hectares[4]; 40% (8,751 hectares) of which is within the ALR. In 2001[5], 6,319 hectares were being farmed which is approximately 29% of the jurisdictional area or 73% of the ALR land base. Between 1973 and 2006, 1,303 hectares were excluded from the ALR, resulting in a loss of approximately 13% of the original ALR area

Map 1: Study area within the City of Kelowna



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[4] The figures presented in this report were calculated using GIS.
[5] Ministry of Agriculture and Lands, Land Use Inventory 2001.

Table 1: ALR Statistics for the City of Kelowna		
	Total Area (ha)	**% of Total Area**
Kelowna Area	21,656	
ALR in Kelowna at ALR designation (1973) [6]	10,054	46%
Land excluded from the ALR (1973-2006) [7]	1,303	6%
Area of ALR (2007)	8,751	40%
Area of ALR in farm use[8] (2001)	6,319	29%

4. METHODOLOGY

Information on exclusion applications was acquired from ALC application records. These records were used to identify all parcels that had an application(s) for exclusion from the ALR that were approved or refused by the Commission between 1973 and 2006. This data was brought into a Geographic Information System (GIS) and overlaid with agricultural land use data acquired by MAL in 2001.

5. ANALYSIS

The following questions guided the analysis:

- How much of the land area of Kelowna was originally and is currently in the ALR?
- What would Kelowna have looked like if land was not in a land reserve?
- What was the area of ALR exclusion applications, where were they located, and were they approved or refused?
- For parcels that were refused exclusion from the ALR, what were the primary land uses and agricultural activities, based on the MAL 2001 agricultural land use inventory? *Note: It was assumed that if the exclusion applications had been approved, the agricultural land use would not be present.*

6. RESULTS

From 1974 to 2006, 188 exclusion applications were recorded in the City of Kelowna. Map 2 shows the properties with exclusion applications; approximately 13% of the original ALR area has been excluded or has been approved to be excluded from the Reserve. Although the presence of the ALR has not completely prevented the loss of agricultural lands, in all probability, farmland would have been lost at a much faster rate[9] if the ALR had not existed, eroding the value and sustainability of the agricultural sector in Kelowna.

[6] This number is calculated by adding the total area of the current ALR and the total area of land excluded or approved to be excluded from the ALR.
[7] The figures presented in this report were calculated using GIS. These reflect final decisions of the Commission where conditions have been met and thus might be somewhat different than those reported by the ALC which reflect all decisions including conditional decisions of the Commission.
[8] Ministry of Agriculture and Lands, Kelowna land use inventory dataset, 2001.
[9] Rate of loss is 43 hectares per year over thirty years.

Table 2 shows the total area of the current ALR and the area of the ALR **if all exclusion applications had been approved**. This was calculated by subtracting the area of lands with both refused and approved exclusion applications from the area of the ALR at the time of its designation. This analysis helps to illustrate what the agricultural landscape might have been without the presence of the ALR system. If all lands with exclusion applications had been approved, there would be a 37% reduction in the ALR land area which would have resulted in a significant loss to the productive agricultural land base and the economy. It should be noted that without the ALR in place, the erosion of the agricultural land base may have been more significant than represented by the figures in Table 2.

Table 2: Reduction in ALR Land if All Exclusion Applications had been Approved

	Area (ha)
ALR Area at designation	10,054
ALR Area (2007)	8751
ALR exclusions approved (1973-2006)	-1,303
ALR exclusions refused (1973-2006)	-2,367
ALR Area if all exclusions had been approved	**6,384 (63%)**

Map 2: Location of parcels with exclusion applications in Kelowna

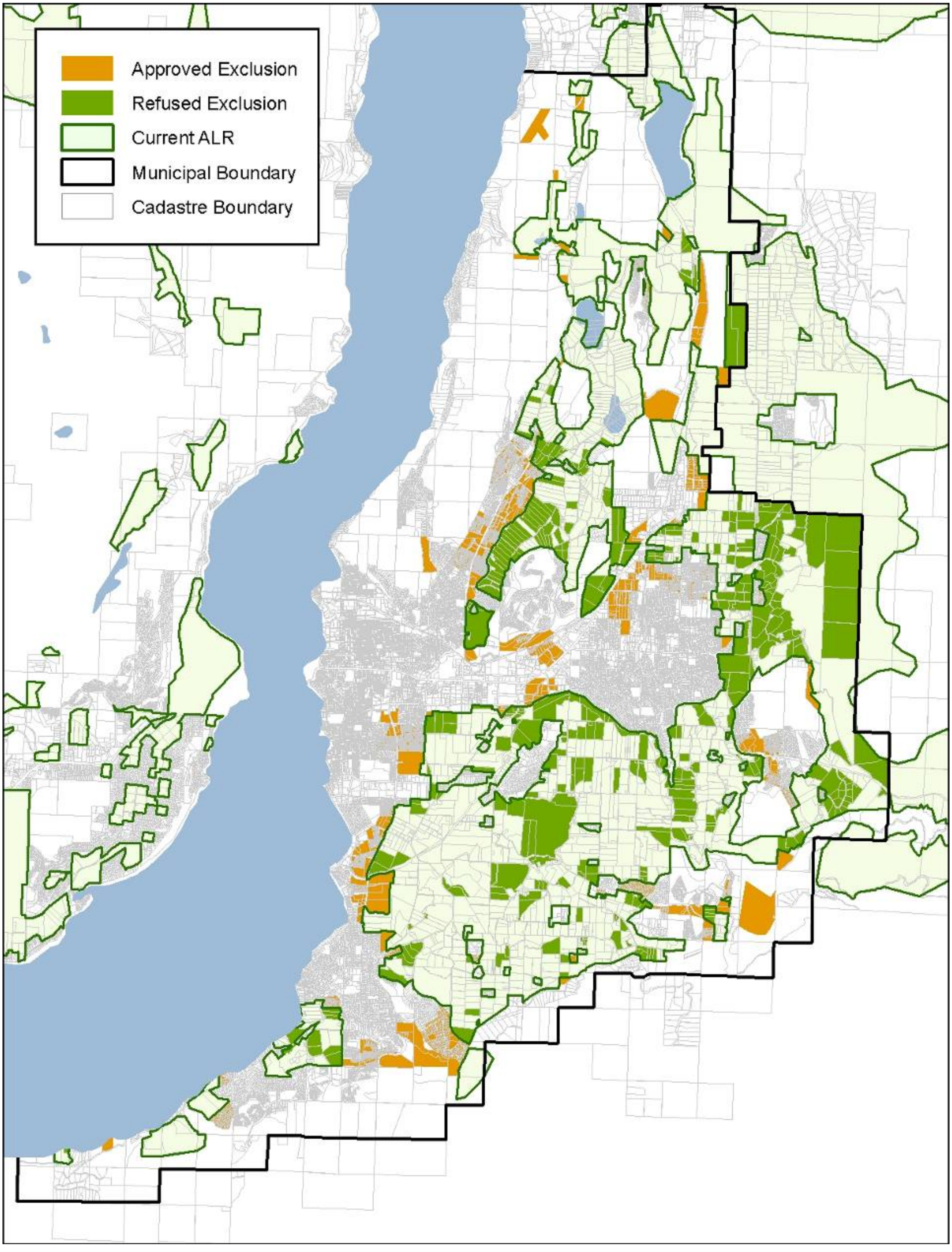


Figure 1 (A and B) illustrates how the Agricultural Land Reserve has been effective in maintaining urban boundaries and controlling urban sprawl. Without the ALR, the agricultural lands in Figure 1A that were subject to exclusion applications may have been developed into residential areas, as depicted in Figure 1B.

Figure 1: Potential landscape if exclusion applications had been approved in eastern Kelowna

A: Current picture of agricultural lands in eastern Kelowna. Parcels with white hatching were subject to ALR exclusion applications. These properties represent diverse agricultural uses from tree fruits to range lands.

B: Potential view of the same area had all exclusion application been approved and properties were developed to a similar density as those to the west.

Figure 2 shows the trend in the number of exclusion applications received annually in Kelowna. While the Commission has no control over the number of applications it receives, the general trend has been a reduction in the number of applications since 1973.

Figure 2: Number of ALR exclusion applications received annually in Kelowna

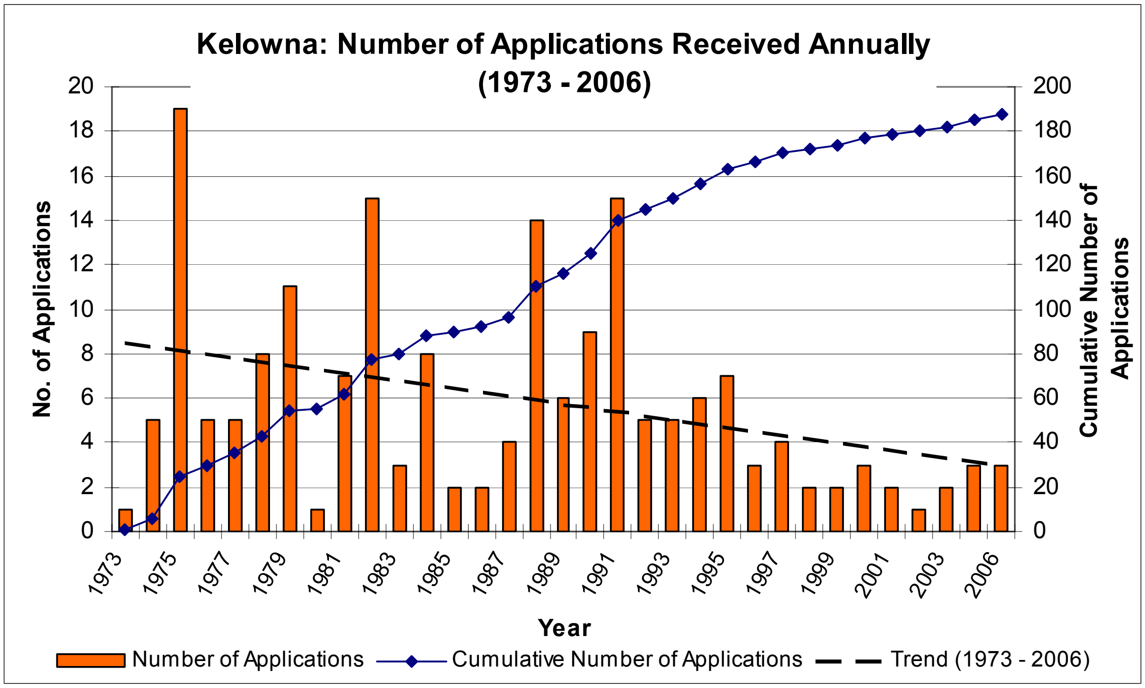
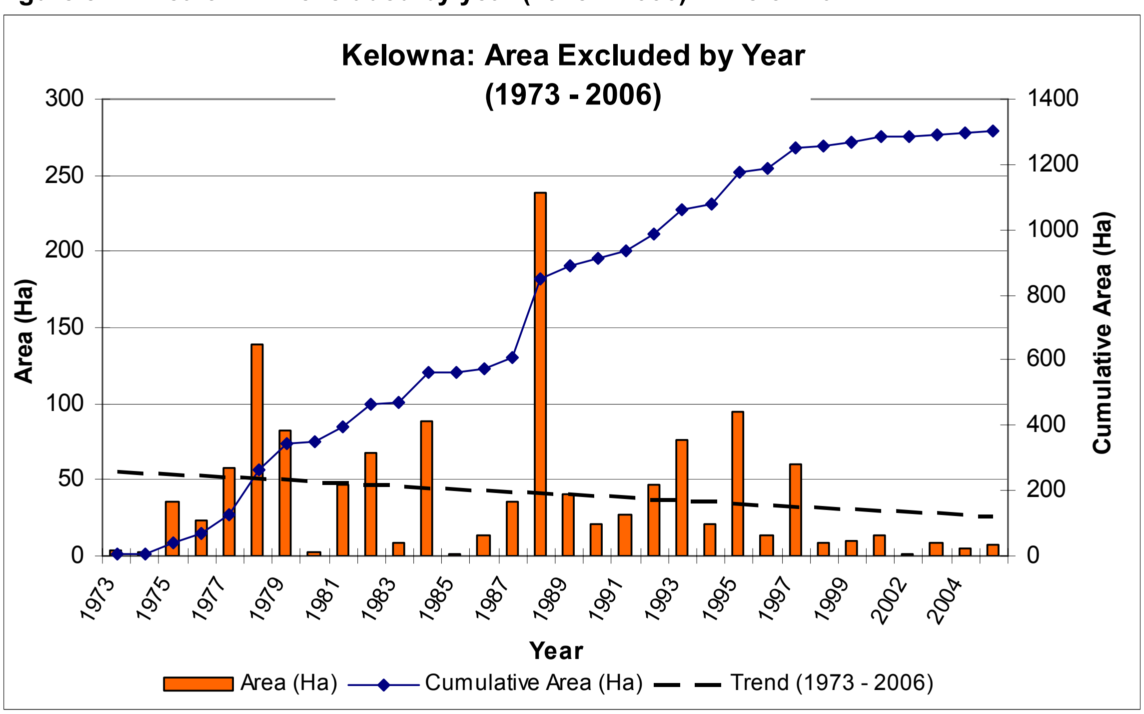


Figure 3 illustrates the area excluded annually from 1973 to 2006. In 1988, the largest area was excluded from the ALR; in this year, 8 exclusion applications were approved, totaling 239 hectares. Since the inception of the ALR, the area excluded annually has been declining.

Figure 3: Area of ALR excluded by year (1973 – 2006) in Kelowna



Refused Exclusion Applications

Since the designation of the Reserve, exclusion applications have been made for 3,670 hectares (Table 3), representing 37% of the original ALR area. Of this area, 24% (2,367 hectares) was refused exclusion. Had it not been for the ALR, these lands would have likely been converted to non-agricultural uses.

Table 3: Area of ALR Exclusion Applications

	ALR Area (ha)	ALR Area (%)
Refused Exclusion	2,367	24%
Approved Exclusion	1,303	13%
Total Applications	**3,670**	**37%**

Agricultural Activities on Parcels with Refused Exclusion Applications

Map 3 illustrates the agricultural activities occurring on areas with refused exclusion applications within Kelowna's ALR. Table 4 shows a general breakdown of the types of land use activities occurring on these parcels.

Table 4: Overview of Land Use (2001) on Parcels Refused Exclusion from the ALR in Kelowna

	Number of Parcels	Total Area (ha)	% of Total Area Refused
Agricultural land use	279	1,764	75%
Non-agricultural land use	125	553	23%
Land use data unavailable	19	50	2%
Total	**423**	**2,367**	**100%**

In 2001, agriculture was the primary land use on 75% (1,764 hectares) of parcels refused exclusion. 23% (553 hectares) were not being farmed and were being used for some other use. Of these unfarmed parcels, 13% were either unused or were being used for hobby agriculture. The remaining 10% were permanently alienated from agricultural through activities such as residential use, industrial use, etc.[10].

If the ALR had not existed, it is assumed that at least 1,764 hectares of actively farmed land in Kelowna would have been lost. Without the ALR, it is likely that much more land would have been converted to urban and other non-farm land uses.

[10] Refer to Ministry of Agriculture and Lands Land Use Inventory Guide for an explanation of the terms primary land use, non-agricultural land use and alienated land.

Map 3: Agricultural activities on parcels with refused exclusion applications

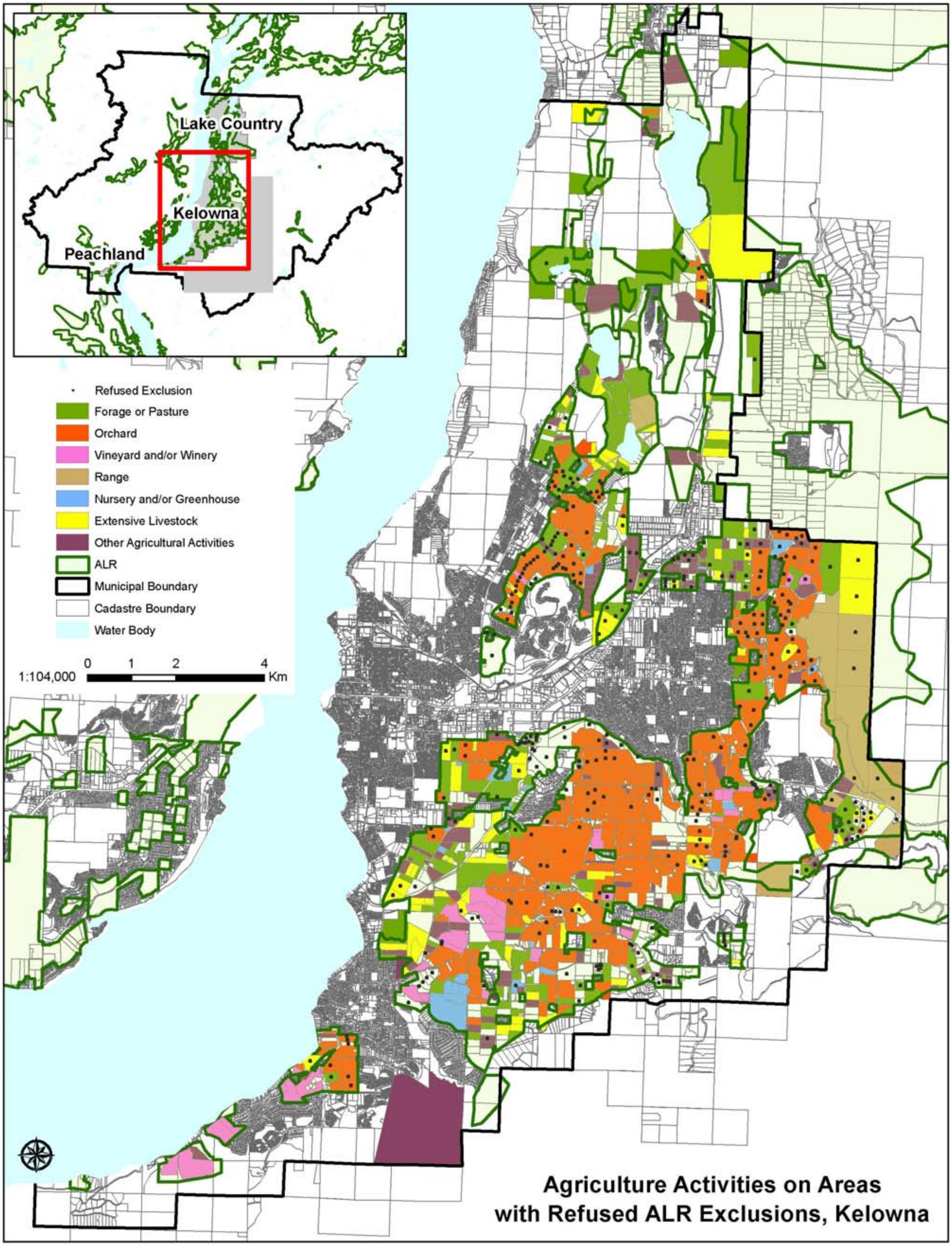


Table 5 provides a detailed breakdown of the types of agricultural activities that are occurring on the agricultural lands where exclusion applications were refused.

Table 5: Primary Agricultural Activities on Parcels with Refused Exclusion Applications

Primary Agricultural Activity	Number of Parcels	Area of Use (ha)	% of Total Area Refused
Orchard	149	852	48%
Beef operations	19	409	23%
Forage or pasture	70	315	18%
Other agricultural activities	20	80	5%
Extensive livestock	12	67	4%
Nursery and/or greenhouse	5	24	~ 1%
Vineyard and/or winery	4	17	~ 1%
TOTAL	**279**	**1,764**	**100%**

Economic Value of Agriculture on Parcels Refused Exclusion

Table 6 summarizes the types of primary agricultural activities occurring on properties with refused exclusion applications. The estimated annual crop value was calculated by multiplying the average gross farm receipts per hectare by the total number of hectares for each commodity.

Table 6: Estimated Potential Annual Value of Agriculture on Parcels Refused Exclusion

Primary Agricultural Activity	Area Refused Exclusion (ha)	Average Annual Gross Farm Receipts ($/hectare)[11]	Estimated Annual Crop Value
Orchard	852	$4,740	$4,038,348
Beef operations	409	$189	$ 77,478
Forage or pasture	315	$165	$ 52,009
Other agricultural activities	80	$607	$ 48,590
Extensive livestock	67	$501	$ 33,592
Nursery and/or greenhouse	24	$28,344	$ 680,246
Vineyard and/or winery	17	$7,653	$ 130,094
Total	**1,764**		**$5,060,357**

[11] Statistics Canada, Census of Agriculture, 2001.

Orchard production is the most prominent agricultural activity found in Kelowna[12], which may explain its prevalence here. Trees fruits make up more than 7% of the total crops harvested in B.C. in terms of total gross farm receipts in a 5 year average (1997-2001)[13]. The estimated potential annual crop value of the 852 hectares of orchard is $4 million. If these lands had been excluded, the agriculture industry would have potentially lost this annual income.

By refusing the exclusion of 24 hectares of nurseries and greenhouses the potential loss of an estimated $680,246 of gross farm receipts in this sector has been prevented. Although these parcels account for only a small percentage of the refused applications (< 1%) they represent considerable economic value to Kelowna's agriculture industry.

Of the parcels refused exclusion, 17 hectares were in vineyards in 2001, with an estimated annual value of $130,094. The wine industry in the Okanagan, including Kelowna, is world-renowned, drawing tourists to the region and bringing economic value to the community that well exceeds the crop value of the vineyards.

7. SUMMARY

The results of this study demonstrate that without the ALR, 24% (2,367 hectares) of the original ALR land area would have been permanently removed from Kelowna's agricultural land base. The loss of agricultural land would likely have had a negative impact on the agriculture industry in Kelowna. Despite the loss of some agricultural land to urban development (1,303 hectares), the area where exclusion was refused is largely (76%) in production, generating an estimated $5 million in annual gross farm receipts.

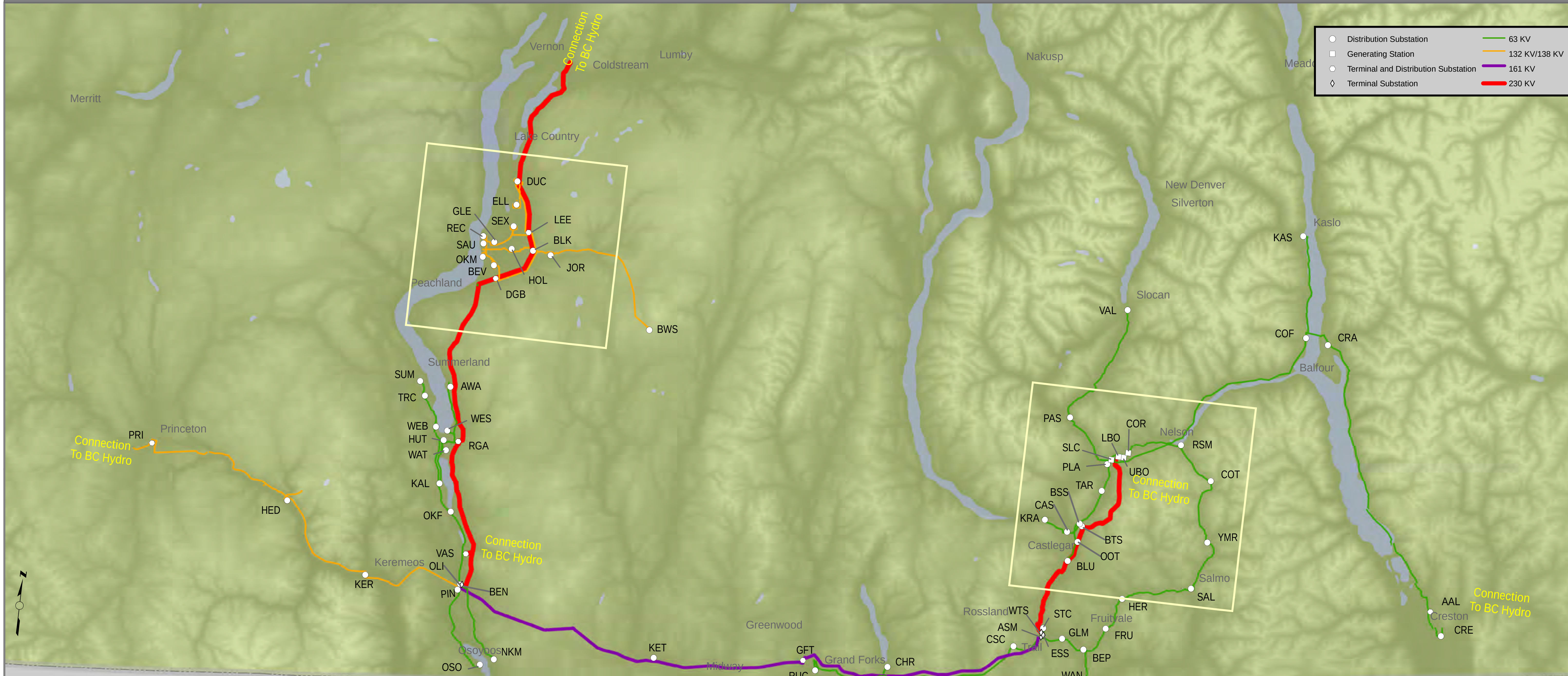
Without the ALR, Kelowna's agriculture industry, landscape and overall community character would be significantly different. This study demonstrates the effectiveness of the Agricultural Land Reserve in preserving Kelowna's valuable farmland and its associated agricultural industry.

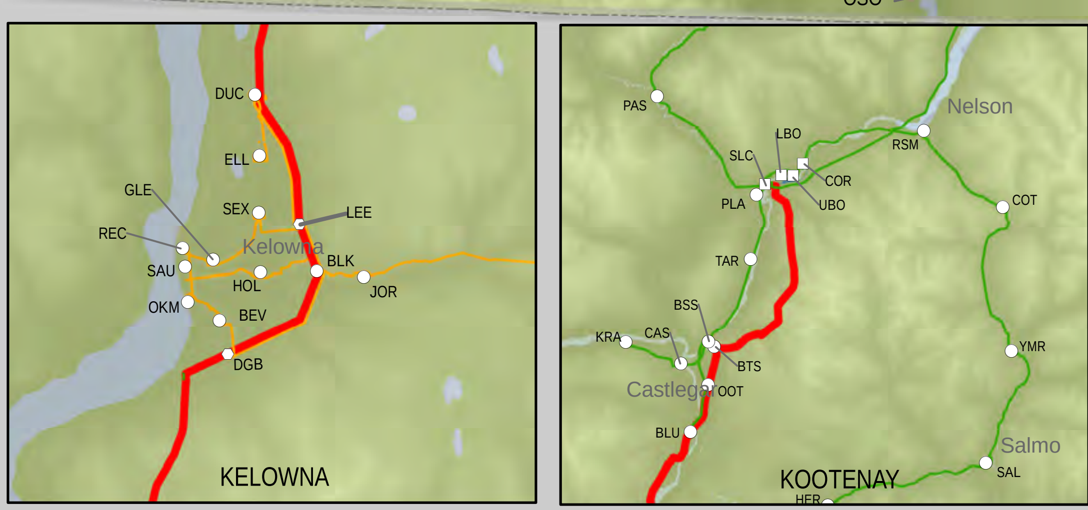
[12] Ministry of Agriculture, Food and Fisheries, 2005
[13] Ministry of Agriculture, Food and Fisheries, Fast Stats, 2004

Appendix D-1

Geographic Transmission Line Overview

FortisBC Transmission System



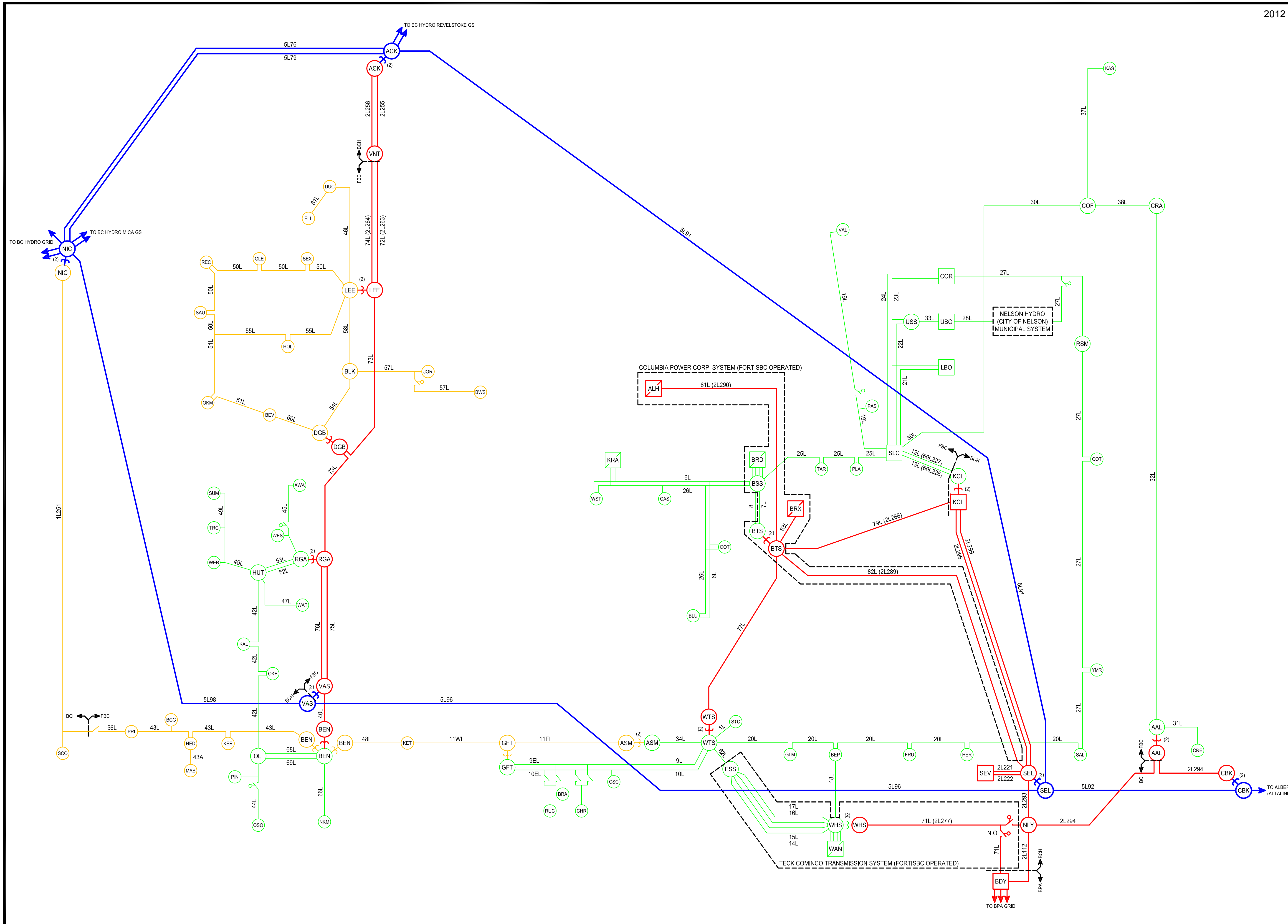


Substation Names

ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	COR	CORRA LINN PLANT #4	HER	HEARNS	OLI	OLIVER	SLC	SOUTH SLOCAN PLANT #3
ASM	A.S. MAWDSLEY TERMINAL	COT	COTTONWOOD	HOL	HOLLYWOOD	OOT	OOTISCHENIA	STC	STONEY CREEK
AWA	ARAWANA	CRA	CRAWFORD BAY	HUT	HUTH AVENUE	OSO	OSOYOOS	SUM	SUMMERLAND
BEN	BENTLEY TERMINAL	CRE	CRESTON	JOR	JOE RICHE	PAS	PASSMORE	TAR	TARRYS
BEP	BEAVER PARK	CSC	CASCADE	KAL	KALEDEN	PIN	PINE STREET	TRC	TROUT CREEK
BEV	BENVOULIN	DGB	D.G. BELL TERMINAL	KAS	KASLO	PLA	PLAYMORE	UBO	UPPER BONNINGTON PLANT #2
BLK	BLACK MOUNTAIN	DUC	DUCK LAKE	KER	KEREMEOS	PRI	PRINCETON	VAL	VALHALLA
BLU	BLUEBERRY	ELL	ELLISON	KET	KETTLE VALLEY	REC	RECREATION	VAS	VASEUX TERMINAL
BSS	BRILLIANT SWITCHING (CPC)	ESS	EMERALD SWITCHING (TECK)	KRA	KRAFT	RGA	R.G. ANDERSON TERMINAL	WAN	WANETA PLANT #5 (TECK)
BTS	BRILLIANT TERMINAL (CPC)	FRU	FRUITVALE	LBO	LOWER BONNINGTON PLANT #1	RSM	ROSEMONT SWITCHING	WAT	WATERFORD
BWS	BIG WHITE	GFT	GRAND FORKS TERMINAL	LEE	F.A. LEE TERMINAL	RUC	RUCKLES	WEB	WEST BENCH
CAS	CASTLEGAR	GLE	GLENMORE	NKM	NK'MIP	SAL	SALMO	WES	WESTMINSTER
CHR	CHRISTINA LAKE	GLM	GLENMERRY	OKF	O.K. FALLS	SAU	SAUCIER	WTS	WARFIELD TERMINAL
COF	COFFEE CREEK	HED	HEDLEY	OKM	OKANAGAN MISSION	SEX	SEXSMITH	YMR	YMIR

Appendix D-2

Transmission Single Line Diagram



LEGEND

- GENERATING STATION
- INDEPENDENT POWER PRODUCER (IPP)
- TERMINAL STATION OR SWITCHING STATION
- DISTRIBUTION SUBSTATION
- TERMINAL TRANSFORMER(S)
- MOTOR–OPERATED DISC.
- SECTIONALIZING DISC.

STATION CONFIGURATIONS

- SIMPLE TAP
- SECTIONALIZING TAP
- LINE PROTECTION TERMINAL

VOLTAGES

- 500 kV
- 230 kV
- 138 kV & 161 kV
- 63 kV

FORTISBC

**SYSTEM PLANNING
INTERCONNECTED SYSTEM
2011**

DRAWN BY:	DATE:	APPROVED BY:	DATE:
PMC	FEB 09	PMC	NOV 10

DRAWING NUMBER	REVISION
4-000-8011	2

Appendix E-1

Transmission Lines (North Okanagan)

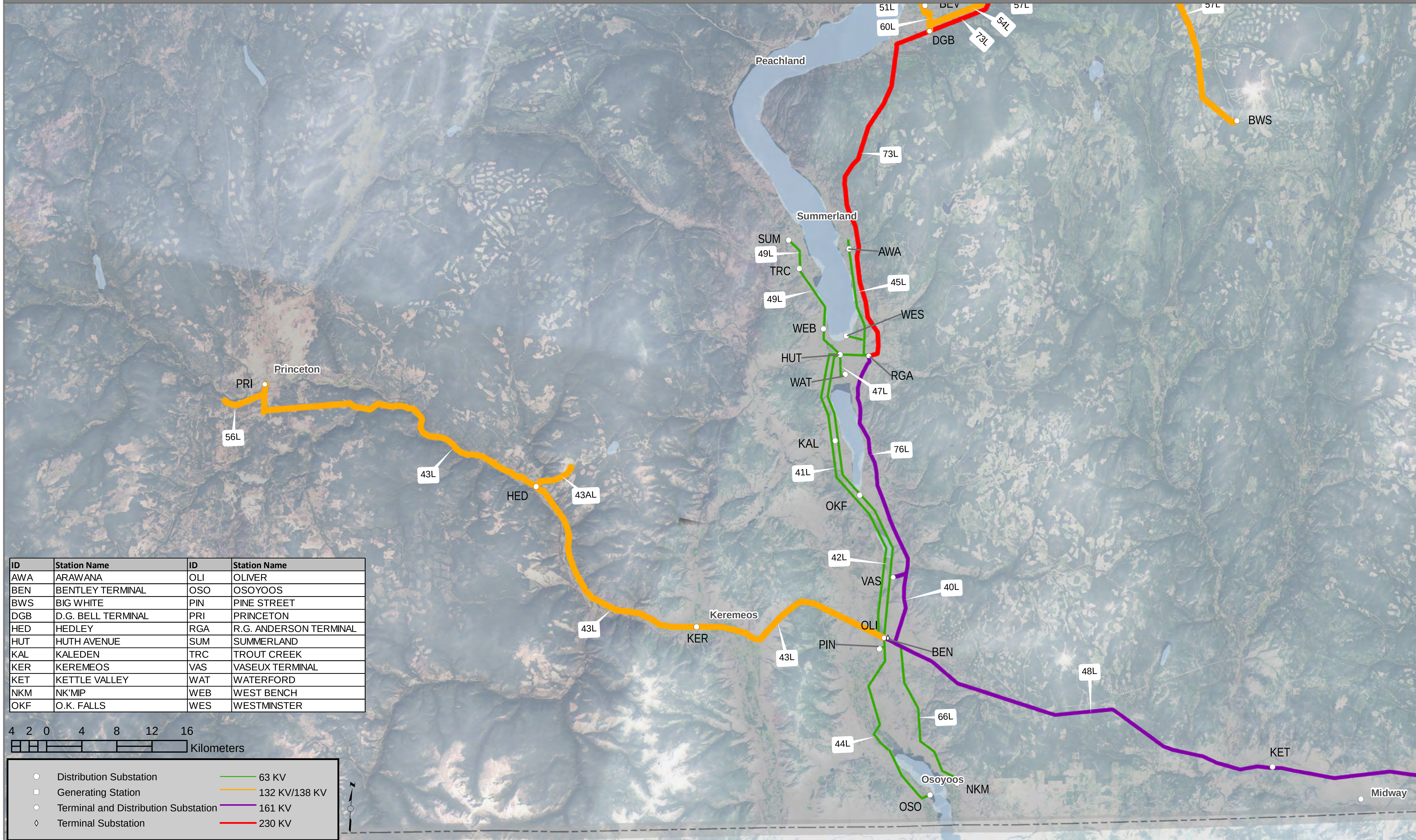
FortisBC Transmission Lines - North Okanagan Region

ID	Station Name	ID	Station Name
BEV	BENVOULIN	HOL	HOLLYWOOD
BLK	BLACK MOUNTAIN	JOR	JOE RICHE
BWS	BIG WHITE	LEE	F.A. LEE TERMINAL
DGB	D.G. BELL TERMINAL	OKM	OKANAGAN MISSION
DUC	DUCK LAKE	REC	RECREATION
ELL	ELLISON	SAU	SAUCIER
GLE	GLENMORE	SEX	SEXSMITH

Appendix E-2

Transmission Lines (South Okanagan)

FortisBC Transmission Lines - South Okanagan Region

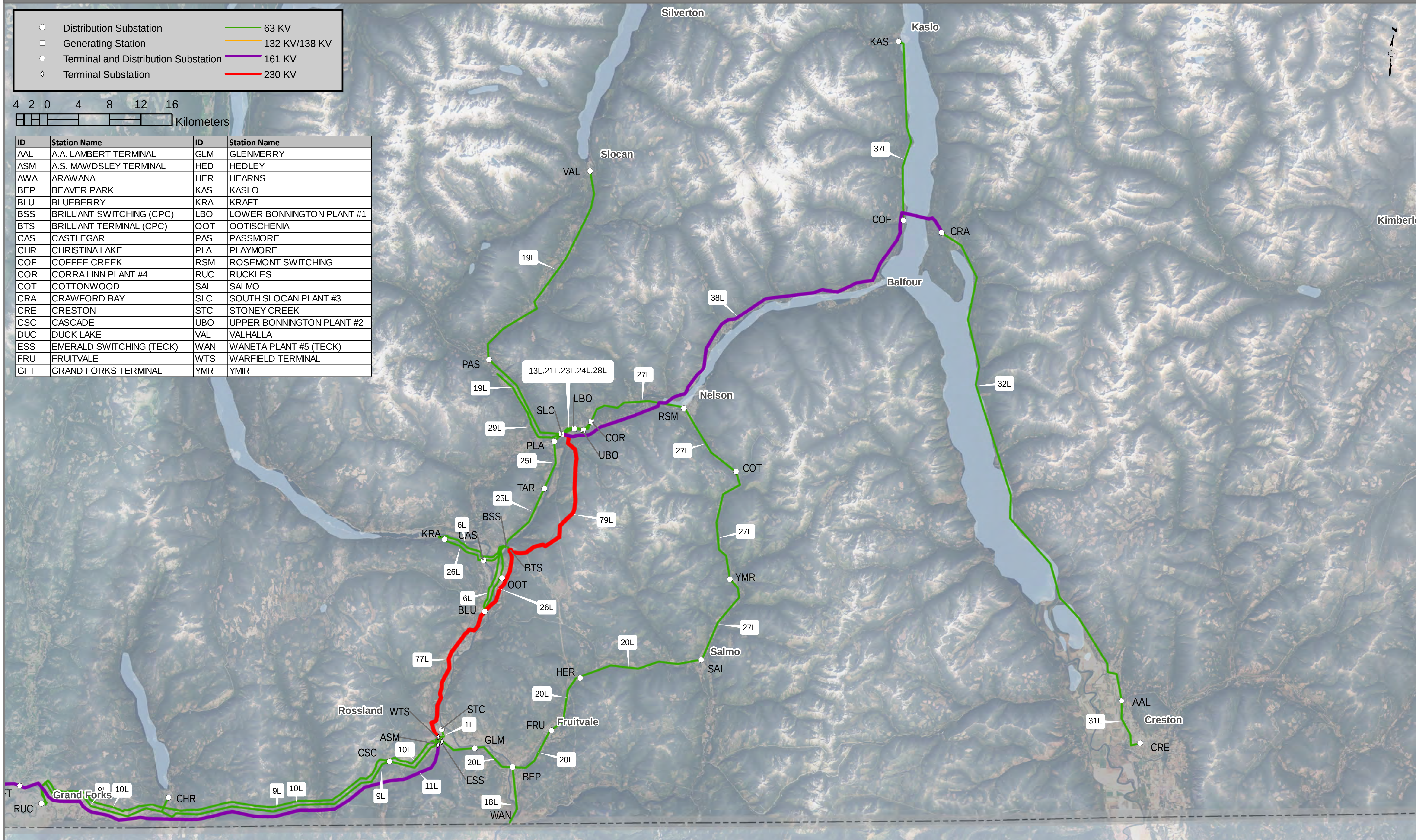


ID	Station Name	ID	Station Name
AWA	ARAWANA	OLI	OLIVER
BEN	BENTLEY TERMINAL	OSO	OSOYOOS
BWS	BIG WHITE	PIN	PINE STREET
DGB	D.G. BELL TERMINAL	PRI	PRINCETON
HED	HEDLEY	RGA	R.G. ANDERSON TERMINAL
HUT	HUTH AVENUE	SUM	SUMMERLAND
KAL	KALEDEN	TRC	TROUT CREEK
KER	KEREMEOS	VAS	VASEUX TERMINAL
KET	KETTLE VALLEY	WAT	WATERFORD
NKM	NK'MIP	WEB	WEST BENCH
OKF	O.K. FALLS	WES	WESTMINSTER

Appendix E-3

Transmission Lines (Kootenay)

FortisBC Transmission Lines - Kootenay Region

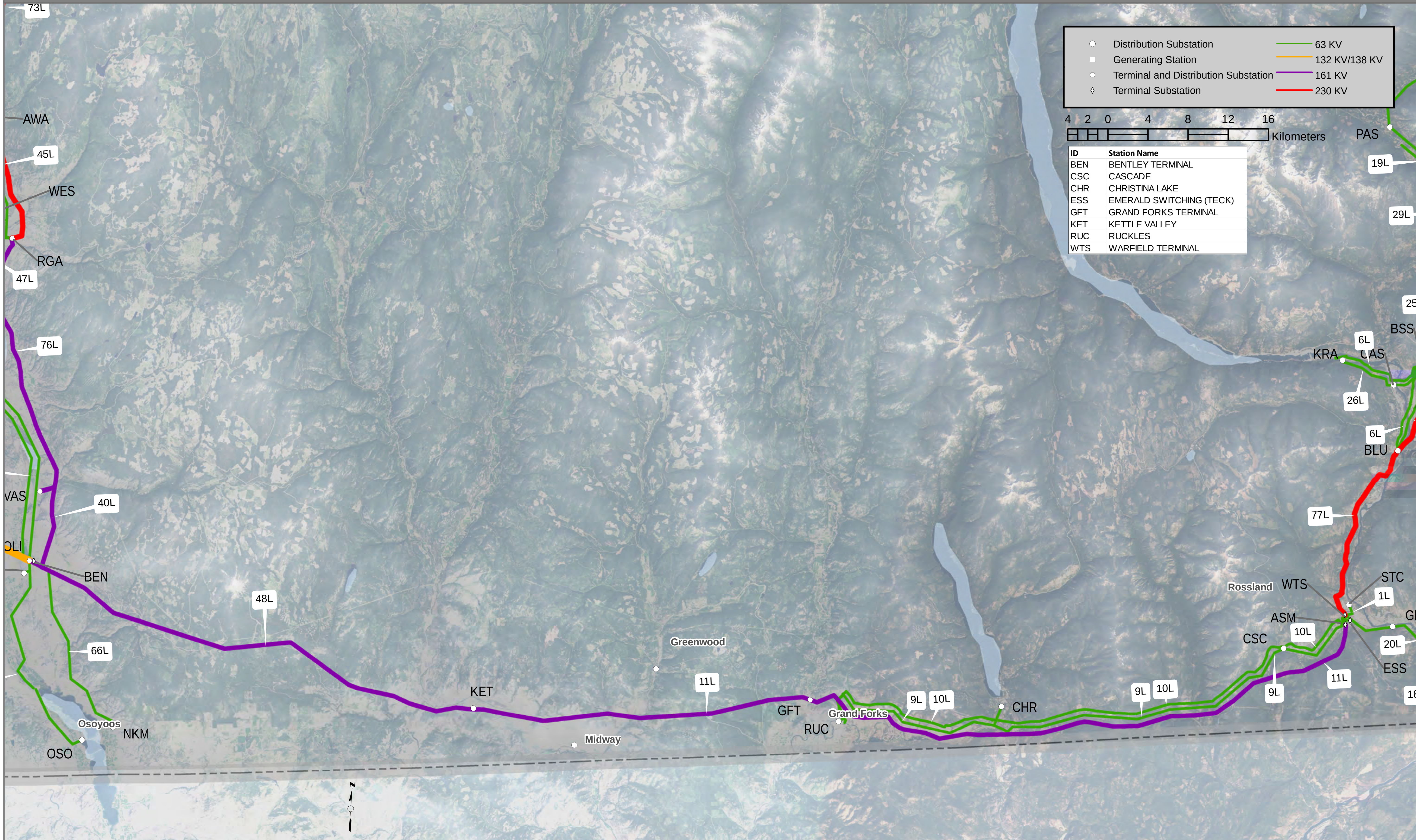


ID	Station Name	ID	Station Name
AAL	A.A. LAMBERT TERMINAL	GLM	GLENMERRY
ASM	A.S. MAWDSLEY TERMINAL	HED	HEDLEY
AWA	ARAWANA	HER	HEARNS
BEP	BEAVER PARK	KAS	KASLO
BLU	BLUEBERRY	KRA	KRAFT
BSS	BRILLIANT SWITCHING (CPC)	LBO	LOWER BONNINGTON PLANT #1
BTS	BRILLIANT TERMINAL (CPC)	OOT	OOTISCHENIA
CAS	CASTLEGAR	PAS	PASSMORE
CHR	CHRISTINA LAKE	PLA	PLAYMORE
COF	COFFEE CREEK	RSM	ROSEMONT SWITCHING
COR	CORRA LINN PLANT #4	RUC	RUCKLES
COT	COTTONWOOD	SAL	SALMO
CRA	CRAWFORD BAY	SLC	SOUTH SLOCAN PLANT #3
CRE	CRESTON	STC	STONEY CREEK
CSC	CASCADE	UBO	UPPER BONNINGTON PLANT #2
DUC	DUCK LAKE	VAL	VALHALLA
ESS	EMERALD SWITCHING (TECK)	WAN	WANETA PLANT #5 (TECK)
FRU	FRUITVALE	WTS	WARFIELD TERMINAL
GFT	GRAND FORKS TERMINAL	YMR	YMIR

Appendix E-4

Transmission Lines (Boundary)

FortisBC Transmission Lines - Boundary



Appendix F

10 Year Transmission Rebuild Plan

FortisBC Ten Year Transmission Rebuild Plan

Executive Summary

FortisBC's transmission system, ranging in voltage from 63 kV to 230 kV, consists of 62 transmission lines which total approximately 1,400 kilometres in length. Several of the transmission lines in the FortisBC system, particularly in the Kootenays, are a vintage of 50 to 70+ years. Historically, repairs to the transmission system have been addressed through the Company's Transmission Rehabilitation Program. The required repairs are identified through a detailed condition assessment conducted every eight years to assess the condition of the line and to document deficiencies, including the identification of structures that require replacement. The structures that are 'flagged' for replacement from the condition assessment are dealt with in the following year's Transmission Rehabilitation Program budget.

In FortisBC's 2009/10 Capital Expenditure Plan (CEP), transmission rebuild projects were submitted for 20 Line and 27 Line. Both lines are of an early 1950s vintage, and are in very poor condition with stubs on many of the structures. Due to the magnitude of the identified scope of work to address the condition of these lines, FortisBC determined it would be unable to complete the required work under the normal Transmission Rehabilitation Program. In its Reasons for Decision contained in Order G-11-09, the Commission determined that the proposed rebuild projects for 20 Line and 27 Line were denied as part of the 2009/10 CEP, and instead directed that the proposed projects be deferred for future submission to the Commission which would include "an overall strategic plan for future transmission line rehabilitation projects, including a ten year planning horizon and a rolling two year capital expenditure plan". FortisBC provides the following submission in response to this directive.

In order to ensure continued reliable service to FortisBC customers, expenditures above those typically set for the Transmission Rehabilitation Program are required to address the age and condition of several of the transmission lines in the Company's service territory. Section 1 below reviews the denial of the previously proposed transmission rebuild projects for 20 and 27 Line. Section 2 discusses the need to address critical rehabilitation work with FortisBC's transmission network, with Section 3 outlining the Company's proposal on the recommended course of action to prudently address the transmission rehabilitation work required to ensure continued safe and reliable service to customers. A review of FortisBC's ten year transmission rebuild plan submitted as part of the 20 Year Integrated System Plan (ISP) is provided, including recommendations on how the ten year plan should be considered by the Commission and stakeholders in its review.

1. 2009/10 CEP - Denial of 20/27 Line Rebuild Projects

In the Reasons for Decision for Order G-11-09 regarding FortisBC's 2009/10 CEP, the Commission noted that the denial of the proposed rebuild projects for 20 and 27 Line was based on two reasons. First, the Commission noted that the projects would include some reconductoring work, including some of the original copper conductor sections of the lines. In this regard, the Commission took note of the denial of the Company's Copper Conductor Replacement Application in Order G-165-08, observing that "there has been no evidence . . . which supports any departure from the determinations in that Order and the related Reasons." Secondly, the Commission noted that based on the scope and estimated costs submitted for the proposed 20 Line and 27 Line Rebuild projects, the expenditures required to address the transmission rehabilitation requirements arising from the condition assessments scheduled for 2009 and 2010 would likely exceed the $20 million threshold for a CPCN application.

With regard to the first consideration provided as part of the Commission's determination on the 20 and 27 Line Rebuild projects, it is important to note that the scope for these projects does not include any reconductoring work, including for the existing legacy copper sections of the lines. The scope of the proposed rebuild projects is limited to the replacement of "red tagged" structures and cross-arms as well as stubbed poles with sufficient deterioration to justify replacement, correction of circuit spacing issues, and improved anchoring where required. In response the second consideration provided as part of the denial of the 20/27 Line Rebuild Projects in the 2009/10 CEP, FortisBC notes that the assessed condition of 20 and 27 Line should be considered atypical of the average condition of the Company's transmission system. Based on the data collected for the assessments completed in 2009 and 2010, it is evident that the identified rehabilitation work is significantly less than that required for the 20 Line and 27 Line Rebuild Projects. Table 1 below provides a summary of the transmission lines assessed in 2009 and 2010, and the associated value of the identified rehabilitation work based on the completed assessments.

Table 1 – Transmission Line Condition Assessment Projects and Estimated Rehabilitation Costs 2009-2010

Line	Location	Year Assessed	Poles	Estimated Rehabilitation Cost
				($000s)
1	Warfield to Stoney Creek	2009	15	2.9
25	Slocan to Playmor to Tarrys to Brilliant	2009	299	17.2
29	Slocan Valley	2009	140	247
31	Lambert to Creston	2009	105	75
30	Coffee Creek to Crawford Bay	2009	26	69
50	FA Lee to Sexsmith to Glenmore to Recreation to Saucier	2009	320	76
49	Huth to West Bench to Trout Creek to Summerland	2009	310	277
	Subtotal	2009	1,215	764.1
30	South Slocan to Coffee Creek	2010	522	972
41	Huth to Kaleden to OK Falls to Oliver[1]	2010	580	792
42	Huth to Kaleden to OK Falls to Oliver	2010	420	115
45	RG Anderson to Westminster to Naramata	2010	290	229
45A	45 Line to Downtown Penticton	2010	48	106
46	FA Lee to Duck Lake	2010	87	60
47	Huth to Waterford	2010	50	14
	Subtotal	2010	1,997	2,288
	Total		**3,212**	**$3,052.1**

[1] 41 Line is being removed under the 2012 Capital Expenditure Plan as it is no longer needed after completion of the Okanagan Transmission Reinforcement Project. A condition assessment was required to gather data for the distribution underbuild portions which is required to serve existing customers.

On a per pole basis (excluding 41L) the estimated rehabilitation costs for the lines assessed in 2009 and 2010 is approximately $860 per structure. In comparison, the estimated per pole rehabilitation costs for the proposed 20L and 27L rebuild projects is approximately $5,340 per structure. It should be noted that these averages are based upon the total pole count for the transmission lines to be addressed, however not all of the structures included within the pole count will require rehabilitation work. An estimated cost per structure based on the total pole count is provided to underscore the significantly higher expenditures required to address the rebuild work for 20 Line and 27 Line as compared to the required work to be conducted under the Transmission Rehabilitation program.

During the 2009/2010 timeframe, urgent repair work has been performed on sections of 20 Line and 27 Line under the Transmission Line Urgent Repairs budget, as well as some rehabilitation work for priority locations under the Transmission Rehabilitation budget. Following completion of this work, the condition assessment reports were updated and re-estimated to reflect the current outstanding amount of work remaining on both 20 Line and 27 Line for submission as part of the Company's 2012/2013 Capital Expenditure Plan. Much of the data from the updated assessment reports is included in this document. Both of these projects will commence with one line being completed per year in order of priority in an effort to levelize the resourcing requirements and cost.

2. Addressing Necessary Transmission Rehabilitation Work

Before discussing the details of FortisBC's plan to address required transmission rebuild work, it is important to understand what is meant by rebuild in the context that it is being referred to in this submission. Transmission rebuilds are focused on the replacement of:

- previously inspected "red tagged" structures and cross-arms;
- stubbed poles that have deteriorated enough at the pole tops and cross-arms to justify replacement; and
- correction of circuit spacing issues, and improved anchoring where needed.

The transmission rebuild projects discussed in this document typically do not include any re-conductoring. All projects identified in this plan are like for like structure replacement and repair work similar in scope to the Transmission Rehabilitation program but are larger in magnitude.

Current condition assessment data is not readily available for every transmission line in FortisBC's system because FortisBC has changed and improved its Condition Assessment reporting structure within the last 5 years. However the line rebuilds that are mentioned in this report have had an assessment performed which is consistent with the criteria of FortisBC's Transmission Rehabilitation program. With the exception of the lines discussed below, none of the other transmission lines in the FortisBC system are expected to require significant amounts of rehabilitation work beyond the scope of work addressed by the normal sustaining Transmission Rehabilitation program.

The Ten Year Transmission Rebuild Plan consists of nine 63 kV transmission lines all located in the Kootenay region. Details of these projects are discussed below. Attachment 1 shows a summary of all the Transmission sustaining projects that are forecast to take place in the next 10 years. The Test and Treat/Condition Assessment spending is shown at the bottom along with the corresponding expected spending for Rehabilitation. The other projects shown in the table represent Transmission Rebuild projects that are discussed in more detail throughout the report. Attachment 2 shows the current condition assessment plan for the transmission system from 2011 to 2025.

3. Ten Year Transmission Rebuild Plan

The transmission lines contained in the Ten Year Plan are those lines that are expected to require much more extensive rehabilitation than intended to be completed under the existing Transmission Rehabilitation Program. The Ten Year Plan was constructed using data from detailed condition and engineering assessments which had been previously completed, along with current operational experience to provide input on where reliability problems are being encountered as a result of condition related issues.

There are two transmission lines, 9 Line and 10 Line, that are also in similar condition to the lines discussed in this document. 9 Line and 10 Line span from the Warfield Terminal Station to the Grand Forks Terminal Station, and source all customers located in Rossland, Christina Lake, and parts of Grand Forks. They also provide backup to the entire Grand Forks area in the event of a terminal transformer failure at the Grand Forks Terminal Station. These lines have been excluded from this plan due to the fact that the majority of the line length, particularly between Cascade substation and Christina Lake substation, may no longer be required and therefore salvaged in the future. The decision on whether to keep 9 Line and 10 Line in service between Cascade and Christina Lake will be based on whether it is more economical to rehabilitate the lines to an acceptable state or to install a second terminal transformer at the Grand Forks Terminal station. Details of the plan regarding this can be found in the 2012/2013 Capital Expenditure Plan under the Grand Forks Transformer Addition project. The sections of 9 Line and 10 Line remaining between Grand Forks Terminal and Christina Lake and between Warfield Terminal and Cascade will be condition assessed in 2011 and 2012 respectively as part of the regular Transmission Condition Assessment program. The resulting rehabilitation work required will be covered under the regular Transmission Rehabilitation program in 2012 and 2013 respectively.

The Ten Year Transmission Line Rebuild Plan detail below is being provided for informational purposes only pursuant to the directives contained in Order G-11-09.

20 Line, 27 Line, and 21-24 Line Condition Assessments

As discussed above, detailed engineering assessments have been completed for 20 Line, 27 Line, and 21-24 Lines. The assessments have confirmed that the lines are in relatively poor condition with a number of outages occurring as a direct result of failed insulators, deteriorated poles and cross-arms, and inadequate construction design including the use of back-to-back double arm structures through heavy snow load areas, a lack of ground wire and bonding resulting in prolonged outages from pole fires, and circuit-to-circuit faults due to insufficient spacing between the transmission line and the distribution under-build. The condition of all of these lines (20 Line, 27 Line, 21-24 Lines) has resulted in numerous outages for customers, including periodic outages (often of considerable duration) as a consequence of the deteriorated state of these transmission lines.

As noted in the descriptions, numerous structures on these lines have had steel stubs installed in the past in order to extend the life of the pole. The general principle of the FortisBC stubbing program is to extend the life of the poles by one to two full test/treat cycles on average. Poles that test with three inches of good wood remaining are considered to be acceptable to receive a stub to facilitate extending the life of the pole ("blue tagged" poles), poles with less than three inches of good wood remaining are considered "red tagged" poles, which are typically replaced under FortisBC's existing Transmission Rehabilitation Program. However, due to budget restraints in past years, many of these "red tagged" structures have been stubbed in order to mitigate any possible risk until the pole can be replaced. Poles marked as "red tagged" are also flagged as "do not climb", necessitating the use of additional resources (trucks, personnel) for any emergency repairs that need to be performed. The majority of stubbed structures on 20 Line and 27 Line have been stubbed for 15 years or more. It is rare for a pole to require stubbing before it is at least 30 years old, and in many cases the pole may be considerably older. Consequently, the majority of stubbed structures are well in excess of 45-50 years old. The overall condition of the majority of the stubbed structures on 20 Line, 27 Line and 21-24 Lines are now at a point where the cross-arms and insulation have deteriorated to a level where their replacement on a stubbed pole is an inefficient use of resources as well as a poor long term strategy considering the reliability issues experienced on these lines.

The following pictures illustrate some of the deficiencies and deterioration that characterize the general condition of the lines.

Picture 1: Cross-arm broken off the top of pole on 27 Line

The above cross-arm broke off due to a deteriorated pole top. This is typical of the condition of the poles recommended for replacement.

Picture 2 is a photograph taken of 20 Line in the winter, and is an example of the close circuit spacing between the 63 kV top circuit and the 13 kV distribution underbuild. Note the snow loading on the far phase on the underbuild. This has occurred with the overbuild as well, and in extreme cases has caused contact with underbuild causing outages and damage to customer’s electronic devices.

Picture 2: Snow loading on 20 Line

Picture 3 was taken on 27 Line and illustrates snow that has piled up on the double cross-arm. There are several examples of this structure configuration on 27 Line; a significant portion of this line passes through regions that routinely experience very heavy snowfall. The snow build-up on these double cross-arms can become so severe that it covers the insulators completely, resulting in tracking (leakage current conduction) to the arms and hardware. This tracking has caused several poles and/or cross-arms to burn off creating a fire risk and public safety concern. Structures with this double cross-arm configuration will be addressed as part of the proposed rebuild project.

Picture 3: Snow accumulation on 27 Line double cross-arm

Picture 4 was also taken on 27 Line and shows that the middle conductor on the distribution under-build has broken free from the insulator and come in contact with the pole causing burn damage to the pole. This is a fire, safety, and reliability concern. All of the pictures are examples of the types of issues that will be resolved once the line rebuilds are complete.

Picture 4: Conductor broken off of insulator on 27 Line causing pole burning

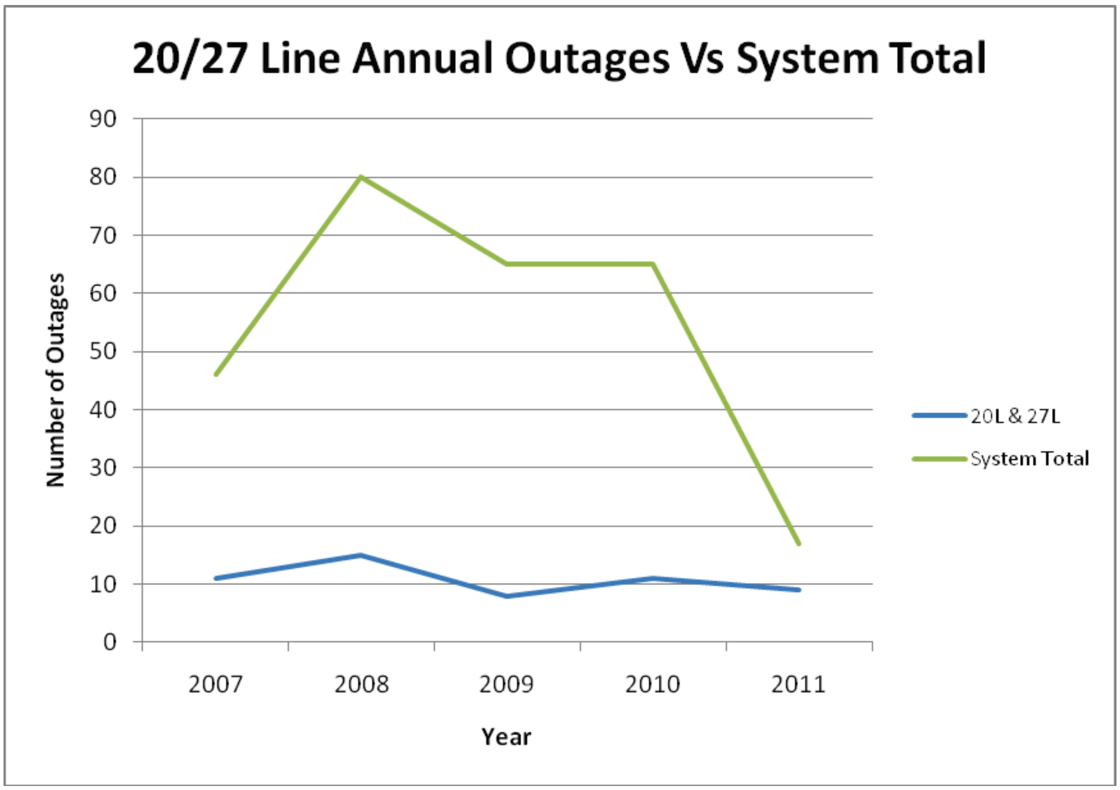
Picture 5 shows a failed crossarm on 20 Line after it was removed. There have been many crossarm failures like this example on all the lines being discussed in this plan. While it may be economical in some instances to replace only the crossarm if the pole is in reasonable shape, the majority of the time the pole is stubbed and in similar condition to the crossarm as they are usually of the same vintage. The prudent approach to address condition related issues such as this is to change the entire structure out at once.

Picture 5: Failed Crossarm from 20 Line

20 Line and 27 Line Reliability

One of the concerns with the 20 Line and 27 Line condition apart from safety is the reliability to the customers served from these lines. As mentioned before the customers served from 27 Line are people located in Nelson, Ymir, and Salmo and from 20 Line are people located in Trail, Montrose, and Fruitvale. In past years FortisBC has experienced numerous outages on these lines due to condition related issues and tree contacts. Below is a graph to show the relative number of outages of both 20 Line and 27 Line with respect to system averages. The graph clearly shows that the reliability of the lines in terms of number of outages is significantly poorer than the system average.

Figure 1 – 20/27 Line Annual Outages verses System Total

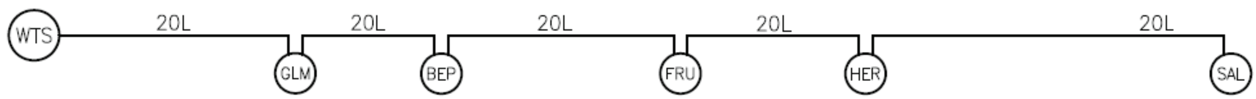


The above plot shows the number of outages per year combined on both 20 Line and 27 Line and on the entire system as a whole. The graph shows that there is roughly ten outages per year for both 20 Line and 27 Line combined. The average number of transmission outages per year on the entire FortisBC system is about 67 excluding 2011 data because the year is not complete. There are currently 62 transmission lines owned by FortsBC. 20 Line and 27 Line make up 3.2 per cent (two divided by sixty-two) of the number of transmission lines in the system and 7.1 per cent (99 km divided by 1390 km) of the transmission line length in the system. However 20 Line and 27 Line account for 14.9 per cent (ten divided by sixty seven) of the total number of transmission outages in the past 6 years. The reliability of these lines is not considered to be satisfactory and FortisBC believes that these figures could be greatly improved if the proposed rebuild work was completed.

It should be noted that the number of outages to date for 20L and 27L (middle of May) in 2011 is approximately equal to the historic average annual number of outages for these lines combined. This shows that the two lines have performed significantly poorer this year as compared to historical results. The outages on 20 Line and 27 Line have made up more than 50 per cent of the outages experienced on the transmission system so far in 2011.

20 Line Rebuild

Single Line Diagram:



Warfield Terminal Station – Glenmerry - Beaver Park – Fruitvale – Hearns - Salmo

Background:

This project is required to maintain service reliability and alleviate safety concerns for the customers in the Trail, Waneta, Montrose, Fruitvale and Salmo areas. 20 Line is a 63 kV circuit that was constructed in 1931. It is approximately 46 kilometres in length, and runs from Warfield Terminal station to Salmo with distribution substations at Glenmerry, Beaver Park, Fruitvale, and Hearns in between. The line includes portions of three phase distribution underbuild between Beaver Park and Salmo. The Beaver Park to Salmo section is also primarily along road and highway rights-of way and is in close proximity to the tree line. Historically, only urgent repairs have been addressed.

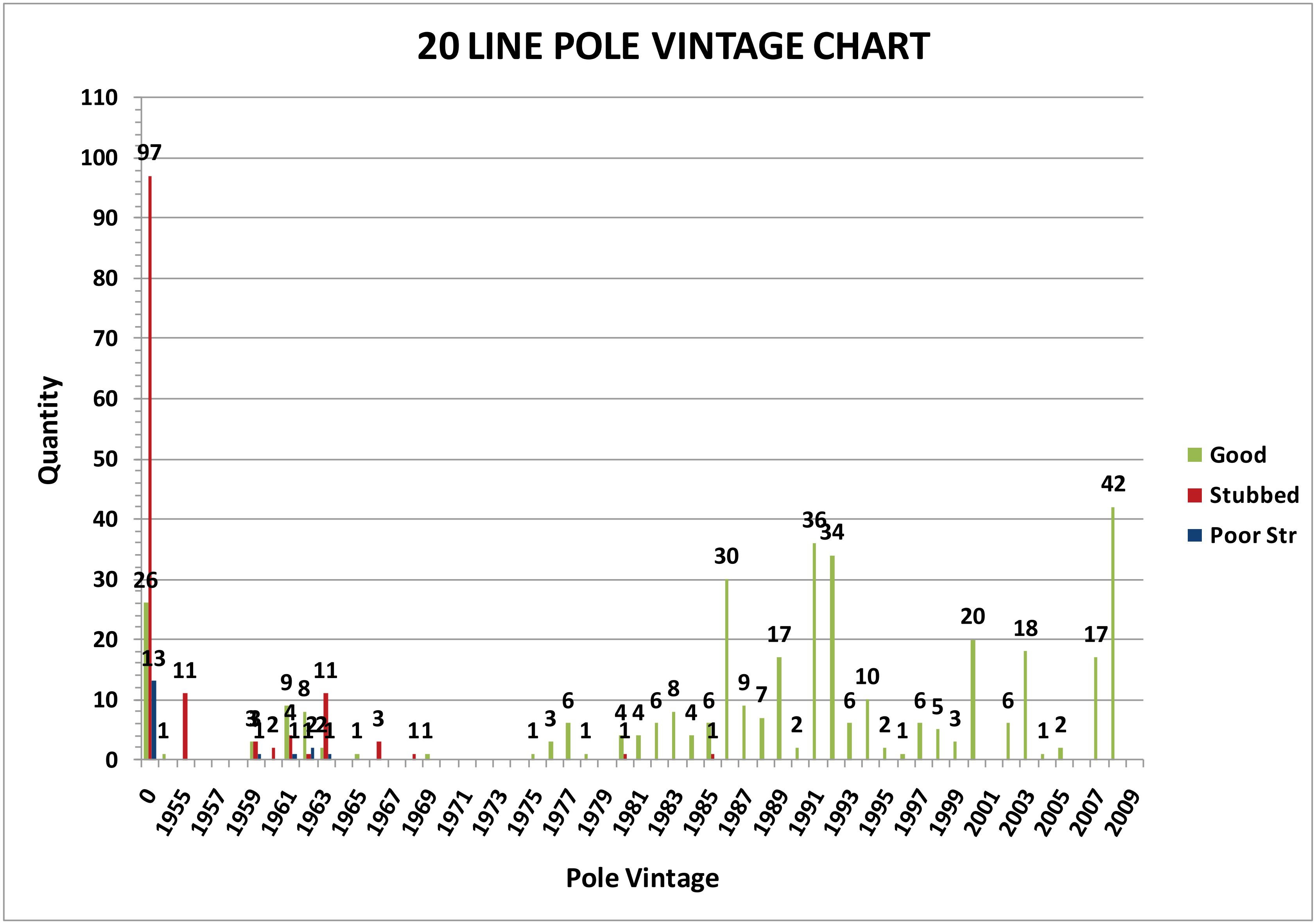
In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The study identified many structures that are either “red tagged” for replacement or stubbed beyond the recommended life extension period. Also identified was significant pole top and crossarm rot, further verifying end of life. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, sub-standard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have all been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report that was created considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centres, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs, using up to date pricing. The report concluded that 52 structures require repairs and 152 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement.

Notice the majority of poles are older than 50 years. The current cost estimate and schedule for the project is shown below.

20 Line Expenditure Plan

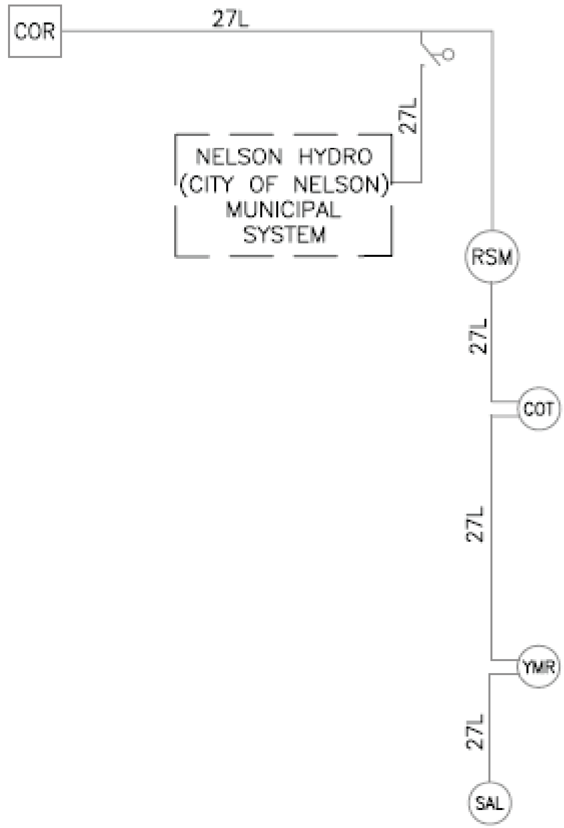
Year	**2013**
Cost ($millions)	4.66


20 LINE POLE VINTAGE CHART
Quantity
Pole Vintage
Good
Stubbed
Poor Str
0
1955
1957
1959
1961
1963
1965
1967
1969
1971
1973
1975
1977
1979
1981
1983
1985
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009
110
100
90
80
70
60
50
40
30
20
10
0

1

27 Line Rebuild

Single Line Diagram:



Corra Linn – Rosemont – Cottonwood – Ymir - Salmo

Background:

This project is required to maintain service reliability and alleviate safety concerns for the customers in the Nelson, Whitewater, Ymir and Salmo areas. 27 Line is a 63 kV circuit that was constructed in 1930. It is approximately 57 kilometres in length and runs from Corra Linn to Salmo with Rosemont Switching Station, Cottonwood, and Ymir substations in between. 27 Line has a variety of configurations consisting primarily of three-phase and single-phase distribution underbuild, as well as some single circuit transmission with no underbuild. The line has many sections with significant setback from the highway and is generally on its own separate right-of-way. There have been some structure changes to the line over the years; but there are still many structures that are either “red tagged” for replacement or stubbed beyond the recommended life extension period including structures with significant pole top and crossarm rot.

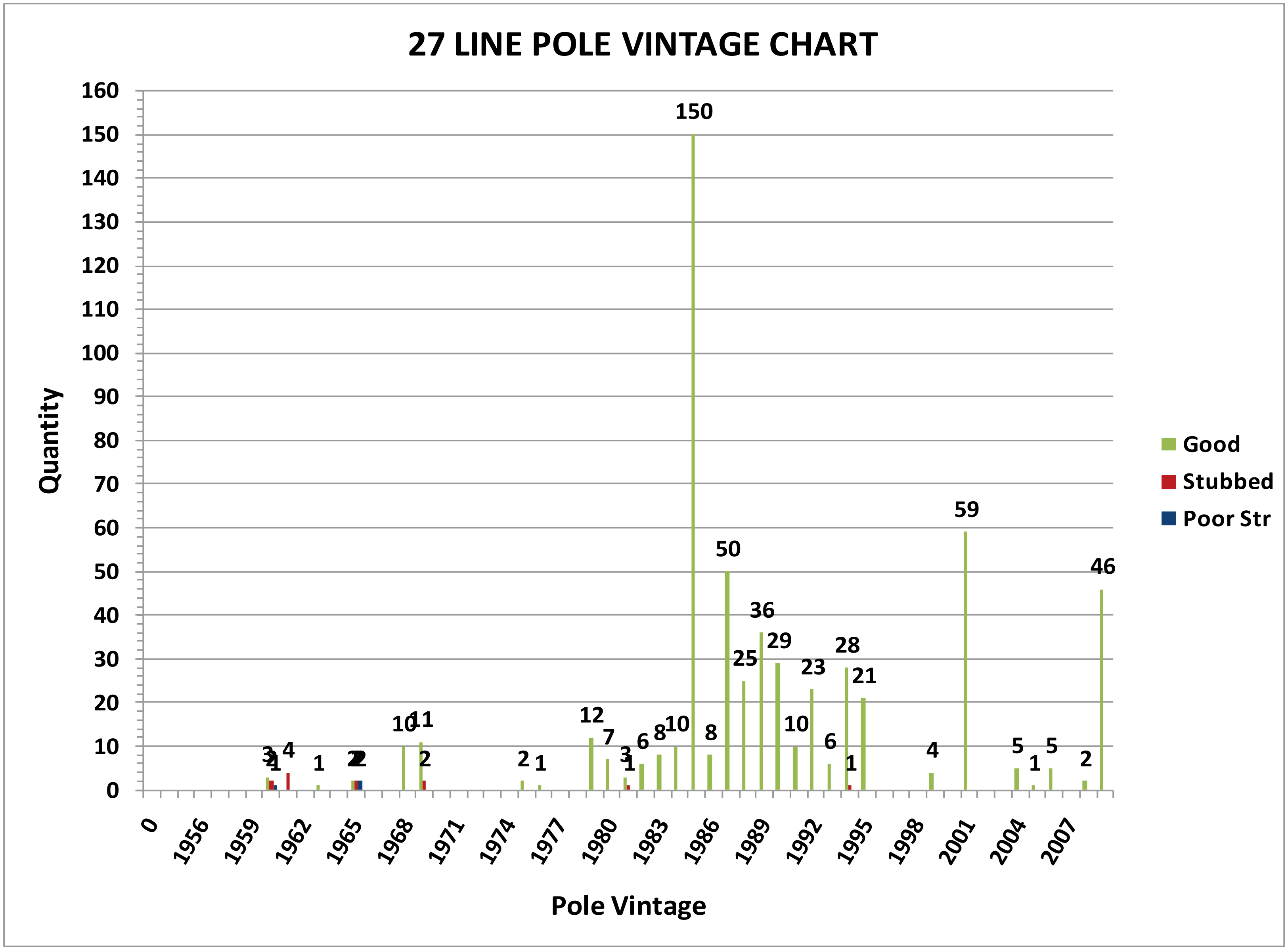
In 2007/08 a detailed engineering assessment was conducted on the line to address reliability and safety concerns reported over the past several years. The assessment concluded that in general the circuit is in poor condition with numerous steel stubbed structures in urgent need of replacement, substandard circuit spacing, and areas with insufficient anchoring. The deficiencies noted have been reviewed and documented on an individual structure basis and a detailed work scope has been formulated. The report considered several options including rebuilding sections on opposite sides of the road, and providing an alternate source of 63 kV to any of the load centers, however these were eliminated as not being feasible.

In 2010 the detailed engineering assessment report was updated to reflect a more accurate scope of work, considering that many structures had already been replaced under urgent repairs and as a priority under the 2009 rehabilitation budget, using up to date pricing. The report concluded that 84 structures require repairs and 14 structures require replacement. The chart on the following page shows the pole vintage distribution along with the counts of which structures are recommended for replacement.

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

27 Line Expenditure Plan

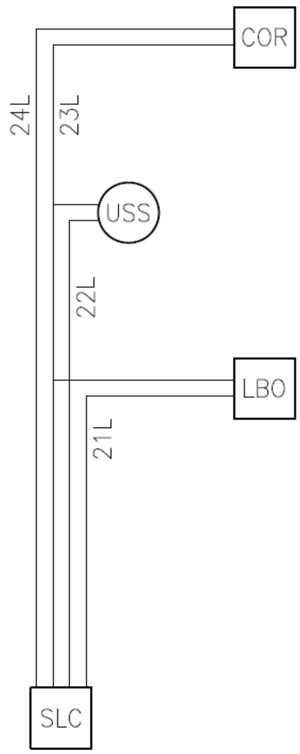
Year	**2012**
Cost ($millions)	1.16


27 LINE POLE VINTAGE CHART
Quantity
Pole Vintage
Good
Stubbed
Poor Str
160
150
140
130
120
110
100
90
80
70
60
50
40
30
20
10
0
0
1956
1959
1962
1965
1968
1971
1974
1977
1980
1983
1986
1989
1992
1995
1998
2001
2004
2007

1

21-24 Line Rebuild

Single Line Diagram:



Corra Linn – Upper Bonnington – Lower Bonnington – South Slocan

Background:

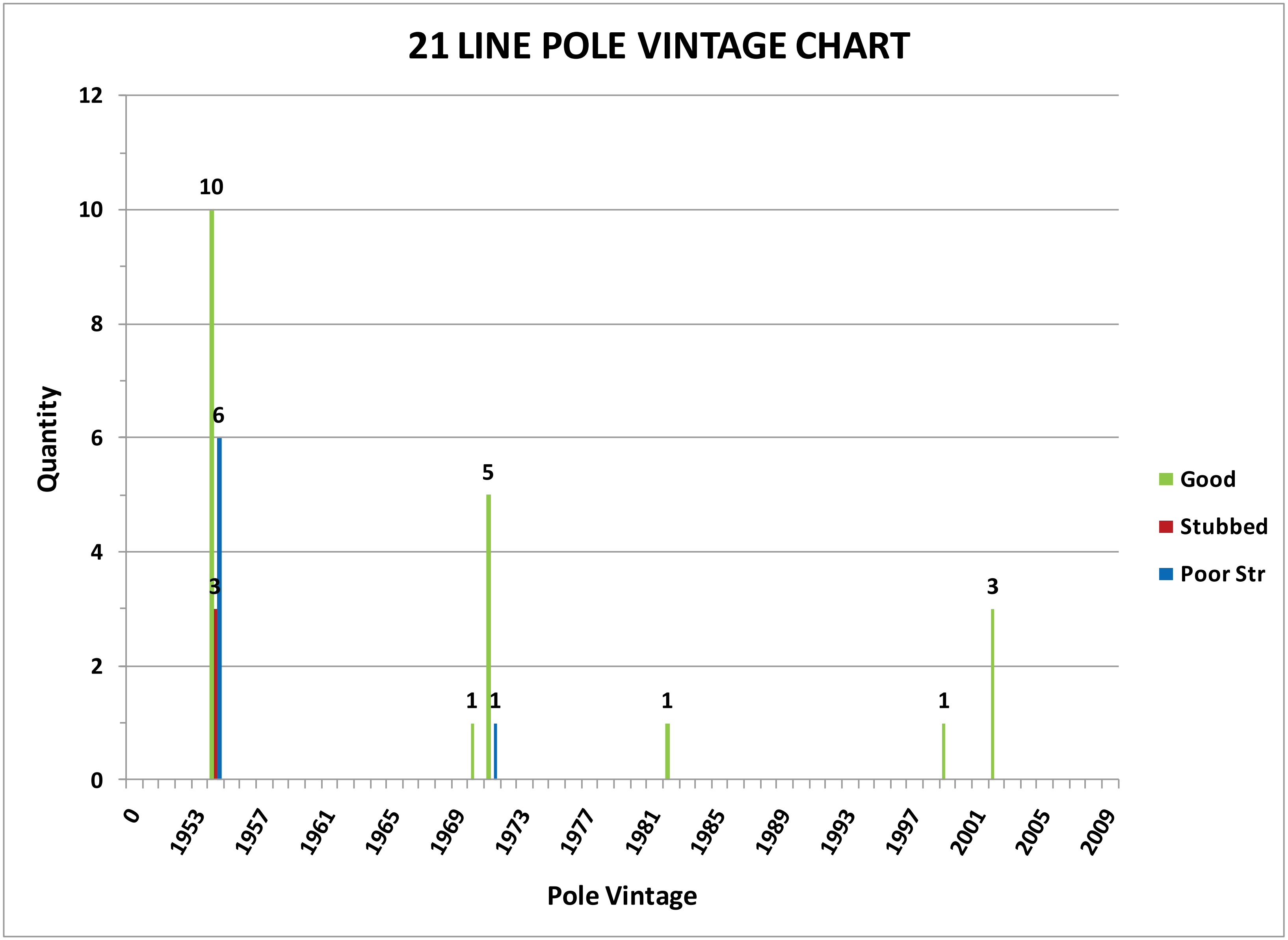
21 - 24 Lines interconnect all four FortisBC owned river plants on the Kootenay River. Line 21 is 2.1 kilometres long and spans from the South Slocan plant to the Lower Bonnington plant. Line 22 is 3.6 kilometres long and spans from the South Slocan plant to the Upper Bonnington plant. Line 23 is 5 kilometres long and interconnects all four river plants spanning from South Slocan plant to the Corra Linn plant. Line 24 is also 5 kilometres long and spans from the South Slocan plant to the Corra Linn plant. These lines are all of the 60+ year vintage and in very poor condition. Similar to both 20 Line and 27 Line a detailed engineering assessment was done in 2008 to identify the deficiencies and risks and explore some options for rebuild. The outcome of the study was to do a like for like replacement of the structures over about a 10-15 year period of time but to replace all urgent structures in the next capital plan. Like the 20 Line and 27 Line assessment reports, the 21-24 Line report was also updated for submission in the 2012-13 Capital Expenditure Plan with up to date scopes and estimates. During the next couple of condition assessment/rehabilitation cycles the remaining substandard condition structures

would be replaced to reduce the effects of the large capital expenditure in one capital plan. Outages on these lines can potentially have large financial implications if the outages result in a generator forced outage. Scope for this project is very similar to the 20 and 27 Line rebuilds with mainly structure replacement. Line 21 requires 10 structure replacements, Line 22 requires 23 structure replacements, Line 23 requires 29 structure replacements and Line 24 requires 37 structure replacements for a total of 99 structure replacements. The charts on the following pages show the pole vintage distribution along with the counts of which structures are recommended for replacement. Notice the majority of poles are over 50 years old.

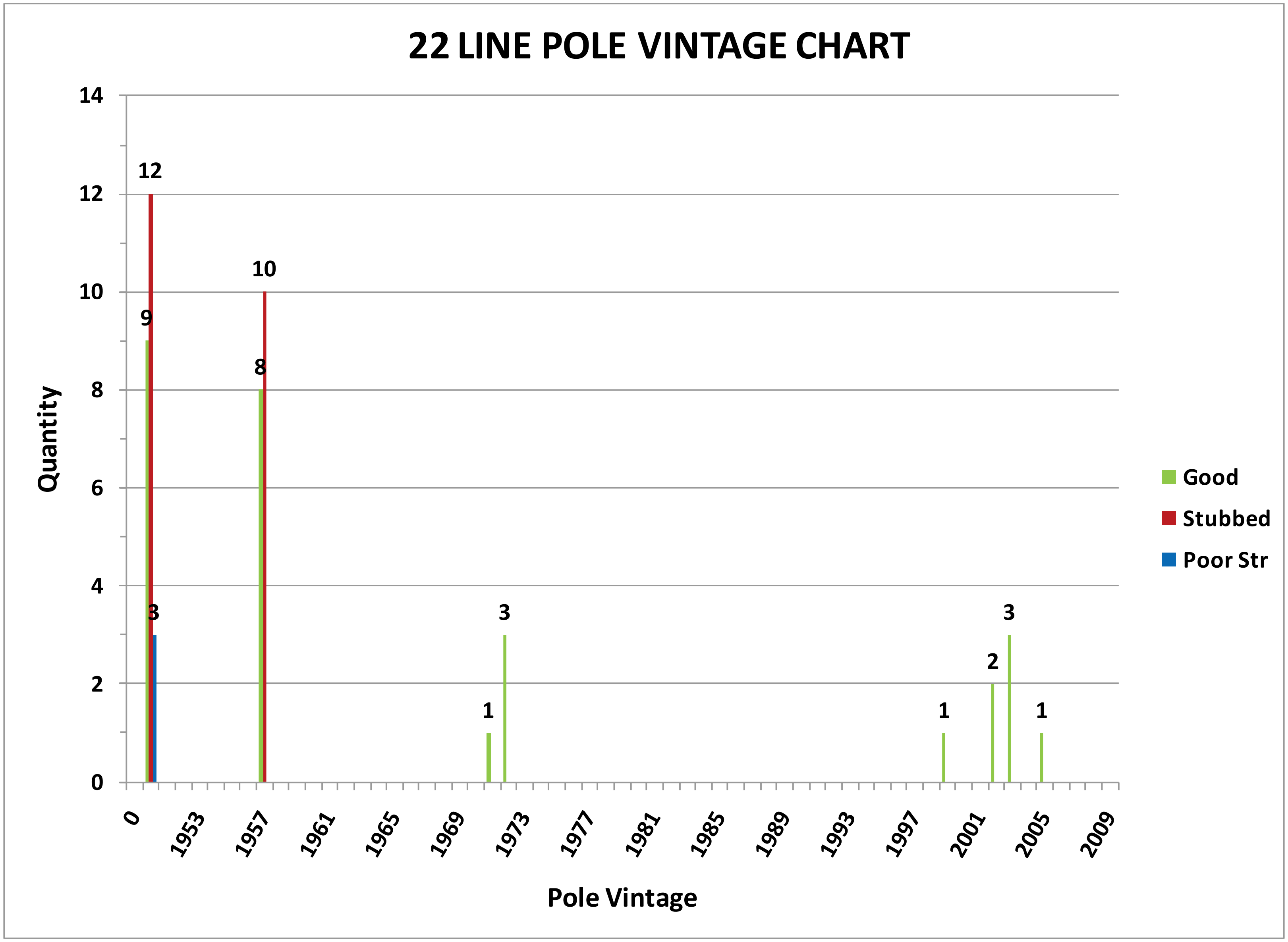
The current cost estimate and schedule for the project is shown below.

21-24 Line Expenditure Plan

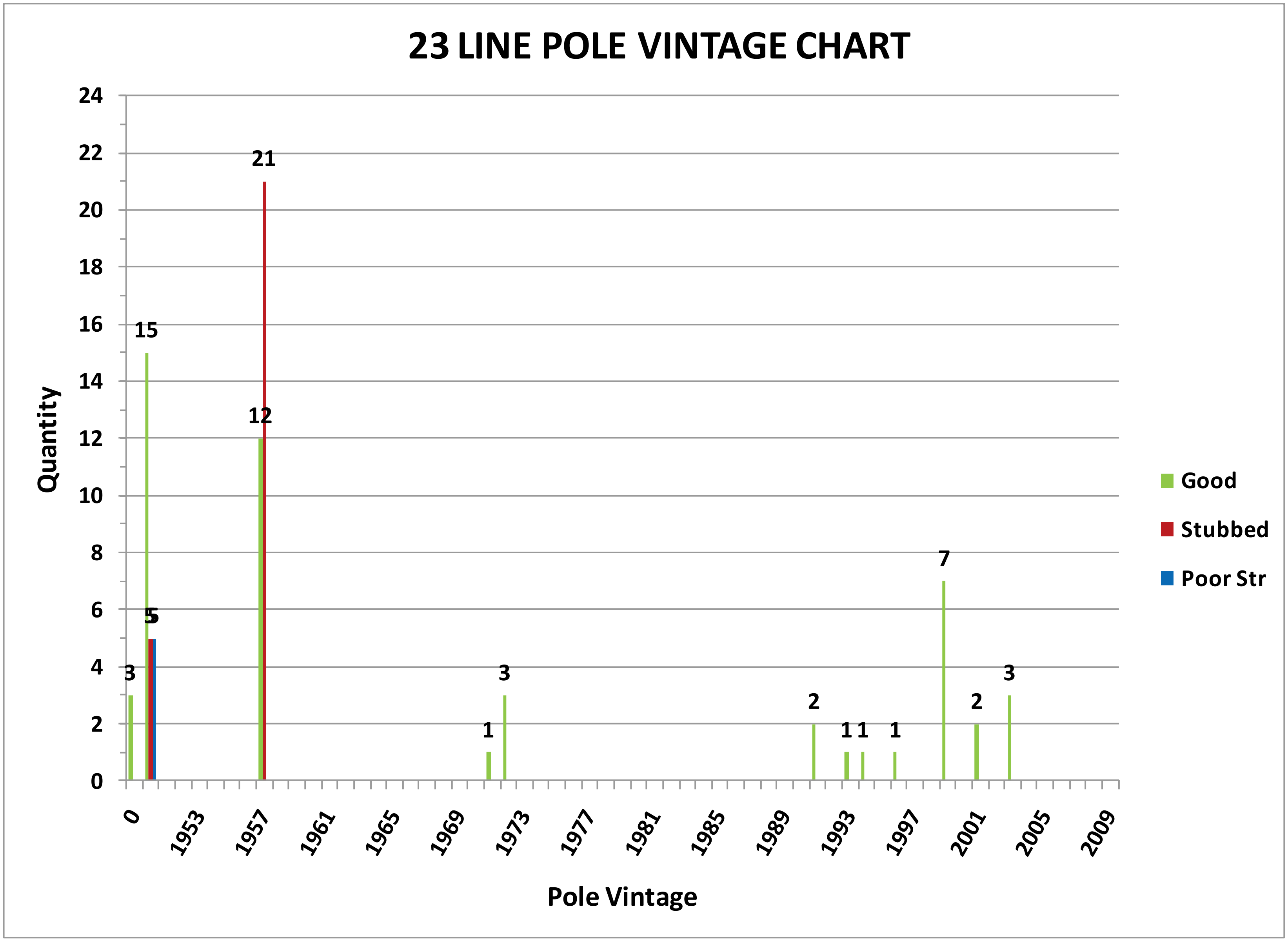
Year	**2012**
Cost ($millions)	2.22


21 LINE POLE VINTAGE CHART
Quantity
12
10
8
6
4
2
0
10
6
3
5
1
1
1
1
3
0
1953
1957
1961
1965
1969
1973
1977
1981
1985
1989
1993
1997
2001
2005
2009
Pole Vintage
Good
Stubbed
Poor Str

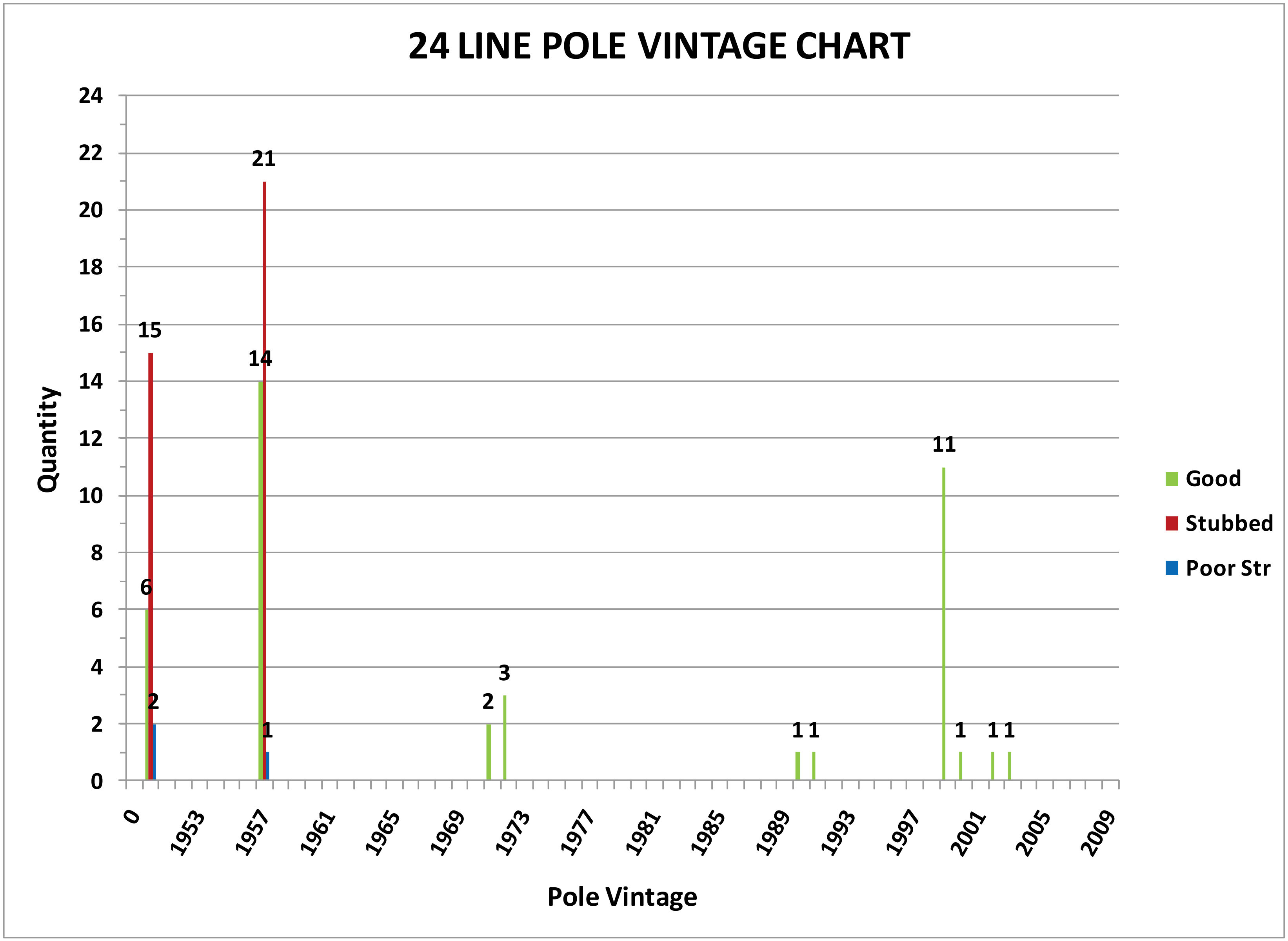
1


22 LINE POLE VINTAGE CHART
Quantity
Pole Vintage
Good
Stubbed
Poor Str
0
2
4
6
8
10
12
14
1953
1957
1961
1965
1969
1973
1977
1981
1985
1989
1993
1997
2001
2005
2009

1


23 LINE POLE VINTAGE CHART
Quantity
24
22
20
18
16
14
12
10
8
6
4
2
0
21
15
12
5
5
3
3
1
2
1
1
1
7
2
3
0
1953
1957
1961
1965
1969
1973
1977
1981
1985
1989
1993
1997
2001
2005
2009
Pole Vintage
Good
Stubbed
Poor Str

1


24 LINE POLE VINTAGE CHART
Quantity
24
22
20
18
16
14
12
10
8
6
4
2
0
15
21
14
6
2
1
2
3
1 1
11
1
1 1
0
1953
1957
1961
1965
1969
1973
1977
1981
1985
1989
1993
1997
2001
2005
2009
Pole Vintage
Good
Stubbed
Poor Str

1

6 Line / 26 Line River Crossing Reconfiguration

Both 6 Line and 26 Line originate at the Brilliant Switching station and split off into four transmission lines that cross the Kootenay River at two locations, one on the upstream (eastern) and one on the downstream (western) side of the Brilliant Bridge on Highway 3A. This creates two dual source supply lines for the Castlegar area (see Figure 2) current configuration . One loop supplies the Castlegar substation, Interfor Forest Products and ties in with Zellstoff Celgar while the other loop supplies the Ootischenia and Blueberry distribution substations.

This project involves work on the transmission lines on the upstream and the transmission and distribution lines on the downstream side of the bridge crossing the Kootenay River at the north east end of Castlegar.

In 2009, FortisBC experienced a pole top failure on one of the distribution river crossing structures, resulting in a live conductor falling into the Kootenay River. The Company/external consultant performed an engineering analysis on the remaining river crossing structures and all structures except one, which was replaced six years ago (6L19), showed various signs of requiring rehabilitation or replacement. Four structures were recommended to be replaced in a non urgent manner in the next capital expenditure plan, one structure was considered to be marginal and could possibly last for another eight year cycle and two structures do not have a sufficient pole diameter for current standards.

Various options were explored to determine how to best rehabilitate the crossings, including a like for like rehabilitation of all four river crossings. It was determined that it would be more efficient from an operational and environmental perspective to salvage the upstream transmission river crossings and to create a new tap point between the loops of 6 Line and 26 Line, as shown in the diagram below (see Figure 3) after reconfiguration) than to rehabilitate all four river crossings like for like.

The reconfiguration will reduce the ongoing capital rehabilitation expenditures required to maintain the lines through the condition assessment program. It will also reduce public safety and environmental risk exposure from river crossing failures by eliminating two long redundant spans of conductor across the Kootenay River which is heavily populated with a wide variety of fish including Sturgeon. Figure 3 below shows at a high level the change required to eliminate the two river crossings.

Figure 2

6 Line/26 Line River Crossing Reconfiguration - Before

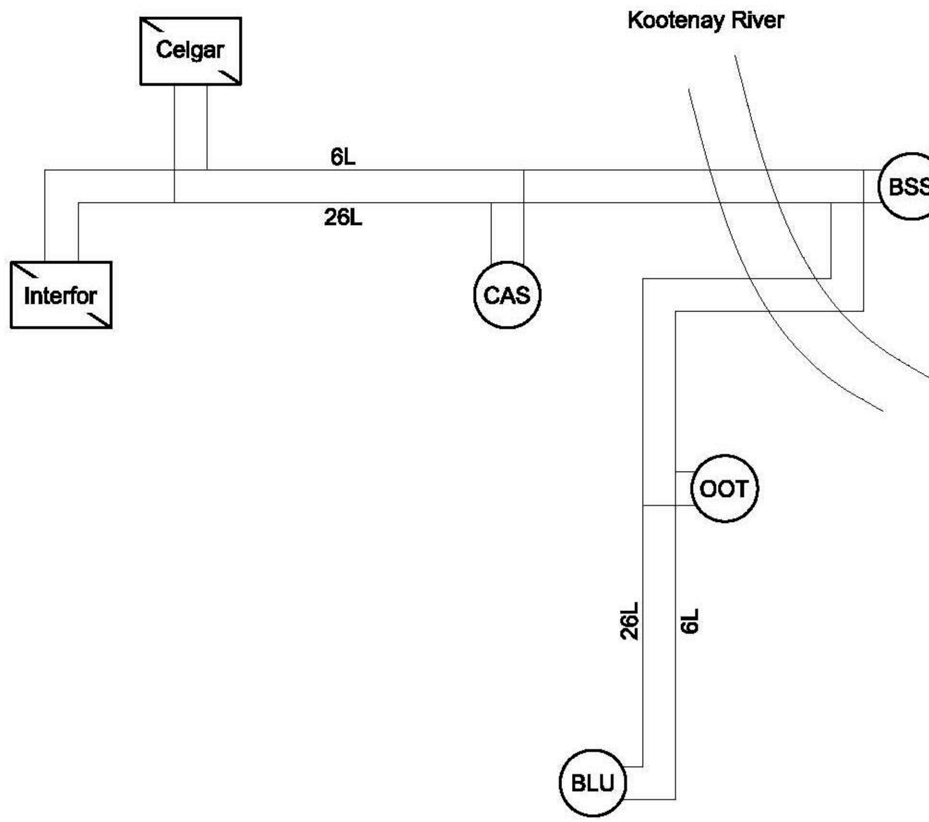
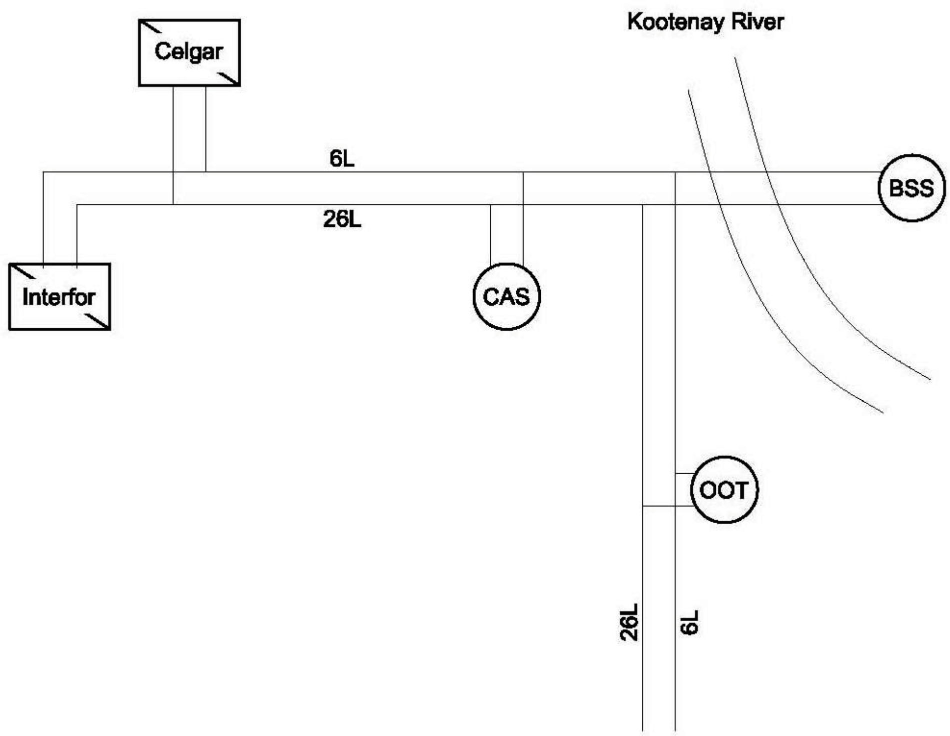


Figure 3

6 Line/26 Line River Crossing Reconfiguration - After



The budget outlined in the following table was derived from engineered planning estimates.

6 Line/26 Line River Crossing Reconfiguration

Year	**2012**
Cost ($millions)	1.19

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. (see Figure 4 for the current configuration). 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 rehab/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. (See Figure 5 for the future configuration)

19/29 Line Reconfiguration

Year	**2012**
Cost ($millions)	0.79

Figure 4

19 Line/29 Line Current Configuration

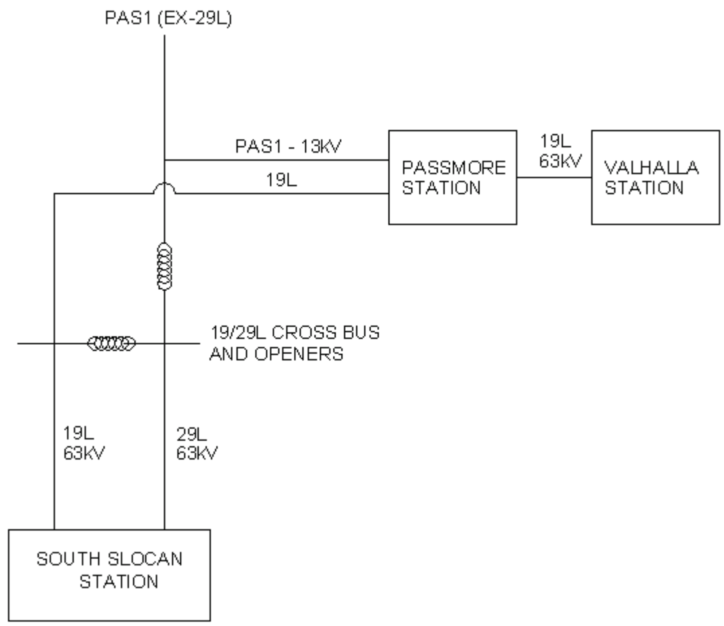
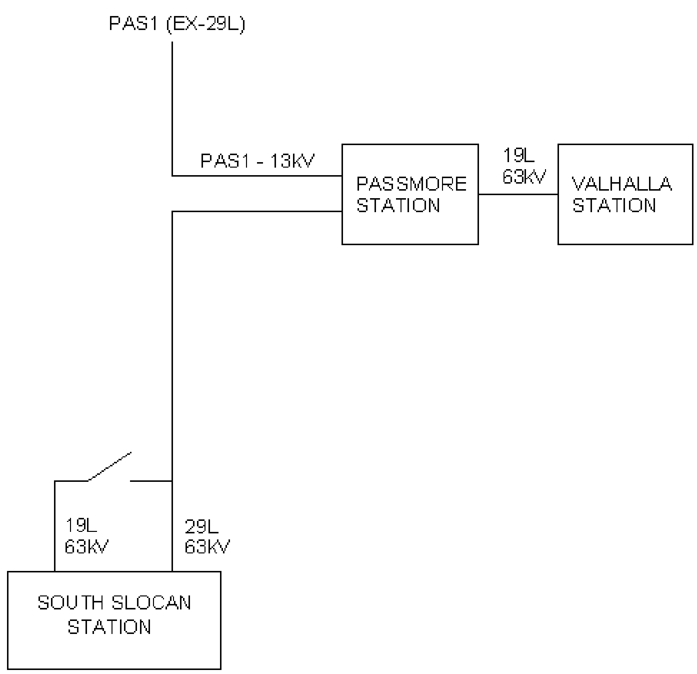


Figure 5

19 Line/29 Line Future Configuration



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 pictures are intended to outline how large these structures are and to give an idea of how long the lake crossing span is.

30 Line Lake Crossing – Geographical Reference

30 Line Lake Crossing Structure 30L240 (East)

30 Line Lake Crossing Structure 30L238 (West)

30 Line Lake Crossing – View from East Structure to West Structure

30 Line Lake Crossing – Marker Balls/Cones

Historically this section of line was inspected and maintained with the use of a “home made” buggy powered with a snowmobile engine. The buggy was lifted unto the line with a crane and the buggy then went out on the line to do the inspection/maintenance with a few employees on board. The current safety standards have progressed considerably since the last patrol (early to mid 1980s) using the buggy and this method is no longer acceptable to the Company given the vintage of the line and the buggy. All inspection and maintenance work now has to be done from the ground or out of a helicopter. The following is a picture of the buggy.

30 Line Lake Crossing – Inspection Buggy

In 2006 this section of line was thoroughly inspected on ground, in a bucket and from the air and a project was proposed to the BCUC to remedy the following deficiencies in the 2009-10 Capital Plan at a loaded cost of $350,000.

30 Line Lake Crossing – Deficiencies

TOWER	DEFICIENCY DESCRIPTION
West Side - Center Phase	Numerous insulator bells with grout checks and cracks
West Side - Center Phase	Paint overspray on insulation – more concentrated on cold end
West Side - South Phase	Numerous broken grounding wire strands on compression tension legs
West Side - South Phase	Paint overspray on insulation – more concentrated on cold end
West Side - South Phase	Numerous insulator bells with grout checks and cracks
East Side – North Phase	Jumper support wood poles have no recent pole tests completed on them
East Side – North Phase	Cold end of one insulator (south side) is missing clevis tongue to yoke plate
East Side – North Phase	Some old 5\8" hardware pins have old steel keys that are rusting
East Side – Center Phase	Connections to ground cable grid is made with split bolts – not preferred
East Side – Center Phase	Considerable paint overspray has occurred on jumper pole insulator string
East Side – South Phase	Center yoke joint cylinder has small crack – appears as a freeze expansion crack; but cannot be verified. Crack is approx 0.004 inch thick at widest point and shows up as small swelled "X"
East Side – South Phase	Numerous insulator bells with grout checks, cracks or pin separation from grout
General	Few 5\8 inch hardware pins have keys only partly inserted.
General	Numerous marker cones are missing and\or are damaged on each of the phases
General	Numerous 5\8 inch hardware pins showing signs of minor bending from tension applied

At very early stages of the project the following information was deciphered;

- The tendered costs for replacing the marker cones alone were approximately $500,000 due to helicopter costs and specialized helicopter equipment to do the work.
- The assessment was primarily from an electrical perspective.
- A preliminary civil inspection revealed that the structures need to be repainted.
- The line was converted to 63 kV and some of the deficiencies noted above are likely not required any longer (Insulation).

Therefore due to the information not being available and the costs to do this rehabilitation project being considerably underestimated the project was deferred in an effort to accurately define the scope of the project and the costs required to meet that scope.

The project will now be spread over two years and two capital expenditure submissions so the low cost assessment can be performed within one capital plan and the higher cost rehabilitation assessment can be done in the following year/capital plan when the detailed costs have been determined.

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.

Replacing the marker cones would typically be a rehabilitation effort, but since these costs are already known (and mostly helicopter time), they will be replaced while the detailed conductor assessment is performed in an effort to reduce overall costs. Given the amount of detail required to assess and rehabilitate this particular section of line, the assessment will be done such that this section of line will not require any further detailed inspections/rehabilitation for 20 years after the rehabilitation project takes place in 2016. Normal inspections will still occur every eight years during the transmission condition assessment program, but the deficiencies captured during this program should be minor in nature.

Rehabilitation Year (2016, 2016/17 CEP)

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

30 Line Lake Crossing Rehabilitation

Year	**2012**	**2013**
Cost ($millions)	0.802	1.521

Attachment 1 – Ten Year Transmission Plan Cost Summary Table

Kootenay		2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	Total	Comments
Line	Section						($000s)						
1	New line from Stoney Creek to WTS											$ -	
6	Brilliant to Castlegar to Celgar		$ 1,185									$ 1,185	6/26L Reconfiguration project.
7	New from BSS to BTS											$ -	
8	New from BSS to BTS											$ -	
9	WTS to Christina Lake											$ -	
9	Grand Forks to Ruckles to Christina Lake											$ -	
10	WTS to Christina Lake											$ -	
10	Grand Forks to Ruckles to Christina Lake											$ -	
11E	Warfield to Grand Forks											$ -	
11W	Grand Forks to Kettle Valley											$ -	
12	South Slocan to Canal Plant											$ -	
13	South Slocan to Canal Plant											$ -	
18	Waneta to Beaver Park											$ -	
19	South Slocan to Slocan City			$ 791								$ 791	19/29L Reconfiguration project.
20	WTS to Salmo			$ 4,663								$ 4,663	20 Line Rebuild
21	Lower Bonnington to South Slocan		$ 2,219									$ 2,219	21-24 Line Rebuild
22	Upper Bonnington to South Slocan												
23	Corra Linn to South Slocan												
24	Corra Linn to South Slocan												
25	Brilliant to South Slocan											$ -	
26	Brilliant to Castlegar to Celgar											$ -	See 6L comments
27	Corra Linn to Salmo		$ 1,161									$ 1,161	27 Liine Rebuild
28	Upper Bonnington to City of Nelson											$ -	
29	South Slocan to Passmore tap											$ -	See 19L comments
30	South Slocan to Coffee Creek											$ -	
31	Lambert to Creston											$ -	
32	Crawford Bay to Lambert											$ -	
34	WTS to Mawdsley											$ -	
37	Coffee Creek to Kaslo											$ -	
38	Coffee Creek to Crawford Bay					$ 802	$ 1,521					$ 2,323	30L Lake Crossing Rehab
62	WTS to ESS											$ -	
77	BTS to WTS											$ -	
79	BTS to Canal Plant											$ -	

North Okanagan		**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**	**Comments**
Line	**Section**						**($000s)**						
46	LEE to Duck Lake											$ -	
50	LEE to OKM via SEX, GLE, REC, SAU											$ -	
51	OKM to BEV											$ -	
54	DGB to BLK											$ -	
55	LEE to HOL to 50L											$ -	
57	BLK to JOR to BWS											$ -	
58	LEE to BLK											$ -	
60	BEV to DGB											$ -	
61	DUC to ELL											$ -	
72	Vernon to LEE											$ -	
73	LEE to RGA											$ -	
74	Vernon to LEE											$ -	
South Okanagan													
40	Vaseux to Bentley											$ -	
41	Huth to Oliver (In future will become distribution tie)											$ -	Once OTR and Huth Bus reconfiguration are complete, 41L will be salvaged.
42	Huth to Oliver											$ -	
43	Bentley to Princeton											$ -	
44	Oliver to Osoyoos											$ -	
45	RGA to Naramata											$ -	
47	Huth to Waterford											$ -	
48	Kettle Valley to Bentley											$ -	
49	Huth to Summerland											$ -	
52	RGA to Huth											$ -	
53	RGA to Huth											$ -	
56	BCH Line to Princeton											$ -	
66	Bentley to NK'Mip											$ -	
68	Bentley to Oliver											$ -	
69	Bentley to Oliver											$ -	
75/76	Vasuex to RGA											$ -	
	TOTAL - REBUILD/Special Project Funding	**$ -**	**$ 4,565**	**$ 5,454**	**$ -**	**$ 802**	**$ 1,521**	**$ -**	**$ -**	**$ -**	**$ -**	**$ 12,342**	

Annual Transmission Line Expenditures	**2011**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**Total**
Rebuild/Special Project Funding	$ -	$ 4,565	$ 5,454	$ -	$ 802	$ 1,521	$ -	$ -	$ -	$ -	$ 12,342
Test&Treat/Condition Assessment	$ 443	$ 522	$ 485	$ 480	$ 547	$ 543	$ 543	$ 457	$ 614	$ 583	$ 5,217
Rehabilitation (Annual Pole Replacement)	$ 1,518	$ 3,372	$ 2,621	$ 2,509	$ 2,424	$ 2,820	$ 2,562	$ 2,696	$ 2,481	$ 3,053	$ 26,056
Total by Year	**$ 1,961**	**$ 8,459**	**$ 8,560**	**$ 2,989**	**$ 3,773**	**$ 4,884**	**$ 3,105**	**$ 3,153**	**$ 3,095**	**$ 3,636**	**$ 43,615**

Attachment 2 – Transmission Condition Assessment Plan 2011-2025

Line #	Section	Cond. Assess. Date
9	Grand Forks to Ruckles to Christina Lake	2011
10	Grand Forks to Ruckles to Christina Lake	2011
43	Bentley to Princeton	2011
43A	Tap to Apex Mine	2011
9	WTS to Christina Lake	2012
10	WTS to Christina Lake	2012
11E	Warfield to Grand Forks	2012
48	Kettle Valley to Bentley	2012
6	BSS to Castlegar to Blueberry to Celgar	2013
18	Waneta to Beaver Park	2013
19	South Slocan to Slocan City	2013
26	Brilliant to Castlegar to Celgar	2013
32	Crawford Bay to Lambert	2013
20	WTS to Salmo	2014
62	WTS to ESS	2014
72	Vernon to LEE	2014
73	LEE to RGA	2014
21	Lower Bonnington to South Slocan	2015
22	Upper Bonnington to South Slocan	2015
23	Corra Linn to South Slocan	2015
24	Corra Linn to South Slocan	2015
27	Corra Linn to Salmo	2015
77	BTS to WTS	2015
79	BTS to Canal Plant	2015
52	RGA to Huth	2015
53	RGA to Huth	2015
56	BCH Line to Princeton	2015
11W	Grand Forks to Kettle Valley	2016
12	South Slocan to Canal Plant	2016
13	South Slocan to Canal Plant	2016
28	Upper Bonnington to City of Nelson	2016
37	Coffee Creek to Kaslo	2016
51	OKM to BEV	2016
54	DGB to BLK	2016
58	LEE to BLK	2016
60	BEV to DGB	2016
74	Vernon to LEE	2016

Line #	Section	Cond. Assess. Date
44	Oliver to Osoyoos	2016
1	Stoney Creek to WTS	2017
25	Brilliant to South Slocan	2017
31	Lambert to Creston	2017
34	WTS to Mawdsley	2017
38	Coffee Creek to Crawford Bay	2017
50	LEE to OKM via SEX, GLE, REC, SAU	2017
55	LEE to HOL to 50L	2017
61	DUC to ELL	2017
40	Vaseux to Bentley	2017
45/45A	RGA to Naramata	2017
49	Huth to Summerland	2017
75/76	Vaseux to RGA	2017
7	BSS to BTS	2018
8	BSS to BTS	2018
30	South Slocan to Coffee Creek	2018
46	LEE to Duck Lake	2018
42	Huth to Oliver	2018
47	Huth to Waterford	2018
10	Grand Forks to Ruckles to Christina Lake	2018
9	Grand Forks to Ruckles to Christina Lake	2019
43	Bentley to Princeton	2019
43A	Tap to Apex Mine	2019
9	WTS to Christina Lake	2020
10	WTS to Christina Lake	2020
11E	Warfield to Grand Forks	2020
48	Kettle Valley to Bentley	2020
6	BSS to Castlegar to Blueberry to Celgar	2021
18	Waneta to Beaver Park	2021
19	South Slocan to Slocan City	2021
26	Brilliant to Castlegar to Celgar	2021
32	Crawford Bay to Lambert	2021
20	WTS to Salmo	2022
62	WTS to ESS	2022
57	BLK to JOR to BWS	2022
72	Vernon to LEE	2022
73	LEE to RGA	2022
21	Lower Bonnington to South Slocan	2023

Line #	Section	Cond. Assess. Date
22	Upper Bonnington to South Slocan	2023
23	Corra Linn to South Slocan	2023
24	Corra Linn to South Slocan	2023
27	Corra Linn to Salmo	2023
77	BTS to WTS	2023
79	BTS to Canal Plant	2023
52	RGA to Huth	2023
53	RGA to Huth	2023
56	BCH Line to Princeton	2023
66	Bentley to Nk'Mip	2023
11W	Grand Forks to Kettle Valley	2024
12	South Slocan to Canal Plant	2024
13	South Slocan to Canal Plant	2024
28	Upper Bonnington to City of Nelson	2024
37	Coffee Creek to Kaslo	2024
44	Oliver to Osoyoos	2024
51	OKM to BEV	2024
54	DGB to BLK	2024
58	LEE to BLK	2024
60	BEV to DGB	2024
74	Vernon to LEE	2024
1	Stoney Creek to WTS	2025
25	Brilliant to South Slocan	2025
31	Lambert to Creston	2025
34	WTS to Mawdsley	2025
38	Coffee Creek to Crawford Bay	2025
40	Vaseux to Bentley	2025
45/45A	RGA to Naramata	2025
49	Huth to Summerland	2025
68	Bentley to Oliver	2025
69	Bentley to Oliver	2025
75/76	Vaseux to RGA	2025
50	LEE to OKM via SEX, GLE, REC, SAU	2025
55	LEE to HOL to 50L	2025
61	DUC to ELL	2025

1

Appendix G

Transmission System Programs

FortisBC
Transmission System Programs
Document 801-03

Date	Rev	Description	Author	Approved
05/25/2011	0	Transmission System Programs	DK, BM, DM	MA

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Transmission System Programs

Revision Date: May 25, 2011 | Rev. 0 | Document No.: 801-03

Table of Contents

Transmission System Programs

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1. Introduction

The Transmission System Programs involve an evaluation of the integrity of the transmission lines physical characteristics and conformance to appropriate regulations. Patrols and assessments are conducted to identify deficiencies in the electrical system owned or maintained by FortisBC that could compromise safety, service reliability, or line integrity.

1.1 Scope

This document outlines the requirements and guidelines for Transmission System programs owned and/or operated/maintained by FortisBC.

The FortisBC and third-party transmission systems are almost entirely comprised of overhead lines. There is a small amount of underground transmission lines scattered throughout the territory as well.

This document provides general information about the Transmission System Programs. Experience and judgement of the patroller is critical for assessing deficiencies and determining the appropriate response for repair.

1.2 Using This Document

It is the responsibility of people using this document to seek clarification, where needed, from the Transmission Planner.

1.3 Competency of Patrollers

The minimum competency required to patrol the electrical transmission system is that of a “qualified employee” (see definitions).

1.4 As-Built Process

The As-built process is very critical to the integrity of data going forward. It is very important that the As-built process is followed when anything is changed in the system whether it is a result of an Urgent Repair, Annual Line Patrol, Rehabilitation, etc. It is not within the scope of this document to outline the As-built process.

2. Benefits of Transmission System Programs

FortisBC conducts a series of patrols and inspections on all transmission system facilities that it owns or operates. These proactive maintenance programs provide information in the form of data, statistics, observations, assessments, and recommendations of corrective action to be performed on the transmission system to ensure public and employee safety, provide appropriate reliability, and intended to prevent failures.

3. Roles and Responsibilities

3.1 Planning

Planning will determine the eight-year cycle for the Condition Assessment program and will also be responsible for the prioritization and modifications to the schedule, if necessary, over the course of the cycle. The schedule and any modifications to the schedule have to be reported to the ArcFM (GIS) group by planning. Planning will work with Project Management to estimate costs for the Condition Assessment and Rehabilitation programs every capital cycle for submission to the BC Utilities Commission. This document is owned by planning and therefore planning is responsible for any changes or modifications.

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3.2 Engineering

Engineering will be responsible for compiling the Condition Assessment reports and reviewing with Operations and Planning. Engineering will also be responsible for preparing the rehabilitation packages that result from the Condition Assessments.

The ArcFM (GIS) group will be responsible for creating all map books for the Test and Treat and Condition Assessors for the appropriate project area boundaries. Once the data is entered into the ArcFM (GIS) system by the field personnel, the ArcFM (GIS) group will also QA the integrity of the data. The ArcFM (GIS) group will also QA all As-built information once Rehabilitation is complete and entered into the ArcFM (GIS) system.

3.3 Project Management

Project Management will be responsible for the execution of the Condition Assessment and Rehabilitation programs. They will also be responsible for managing scheduling, budget, resourcing, ArcFM (GIS) data entry, and ensure a proper summary report is created for the Condition Assessment program. Project Management will also be required to work with planning to communicate per unit costing of the Condition Assessment program to the Planning department to aid the estimating process for the capital submissions for funding of these programs.

3.4 Network Services/Contractors

Network Services/Contractors will be responsible to perform the Annual Line Patrols and the Condition Assessment program on the eight-year cycle. They will ensure that all deficiencies identified from the patrols get corrected on an annual basis. Network Services/Contractors will also carry out the Rehabilitation work identified from the Condition Assessment program every eight years and provide the proper As-built data to the ArcFM (GIS) group when rehabilitation work is complete.

Once Rehabilitation, for either Condition Assessment or the Annual Line Patrol, is complete on the transmission line, then the As-built group will be responsible for entering the As-built information in the ArcFM (GIS) system.

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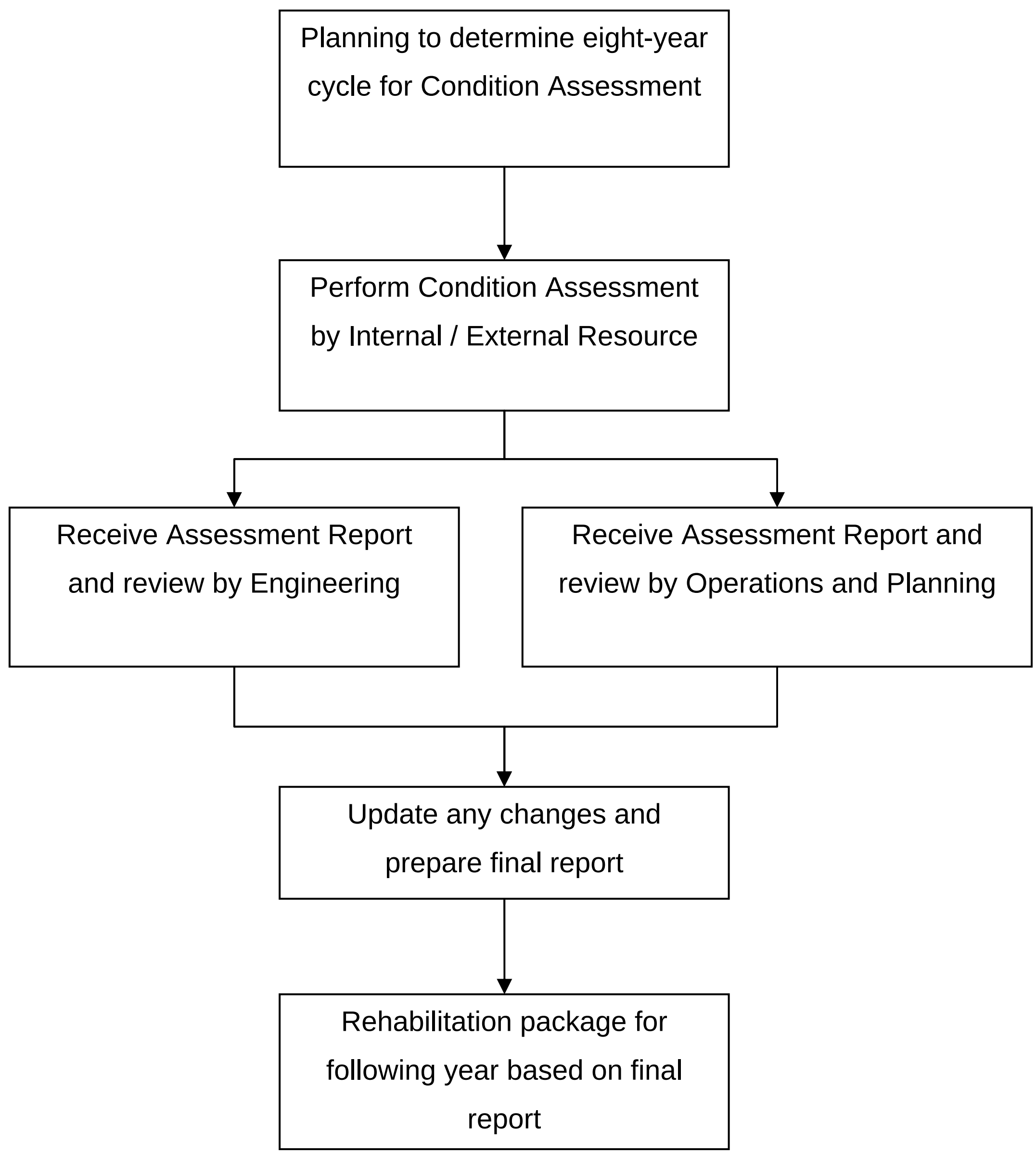
4. Process



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5. Types and Frequency of Patrols

FortisBC has two types of Transmission System Programs:

1. Annual Line Patrol - Operation and Maintenance
2. Condition Assessment Program - Capital

5.1 Annual Line Patrol (ALP)

The ALP is an annual inspection done on all transmission plant as part of the region's Operations and Maintenance (O&M) budget. The regions consist of the North Okanagan, South Okanagan, Kootenay and Boundary. The ALP is a documented patrol by a competent qualified utility employee who successfully completes the internal training, to address imminent safety, environmental or system integrity concerns. Network Services determines the type of visual patrol using criteria such as safety, accessibility, reliability, known defects, outage statistics and system performance.

Foremen are accountable to ensure the ALPs are completed within their respective areas. Power Line Technicians perform the ALP as part of their day-to-day work, and report the line patrolled in ArcFM (GIS) including who did the patrol and the date of patrol.

Patrollers arrange with dispatch to complete all high priority action items identified during the patrol. Anything that is identified that has failed already or shows eminent signs of failure gets replaced under a Transmission Urgent Repair order, which is capitalized. All the other minor deficiencies get repaired under an operating repair order.

Network Services will review the progress of the patrols to ensure all facilities are inspected annually.

5.2 Condition Assessment

The Transmission Condition Assessment program is the Company's capital sustaining program. The program is based on an eight-year cycle of assessing the condition of all FortisBC's transmission line facilities as scheduled by planning. The Condition Assessment program has two parts; a Test and Treat component and an above ground Condition Assessment component.

Test and Treat involves drilling test holes in each pole to confirm the condition of the pole and the addition of pole treatment to reduce internal rot in the pole. The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The Test and Treat program is aimed at the section of pole at the ground level and below.

Condition Assessment is aimed at the portion of the pole above the ground line which inspects things like the pole top condition, anchoring, crossarms, and insulators. If anything fails its inspection during the Condition Assessment or Test and Treat then the deficiency is documented and included in a rehabilitation package. The Condition Assessment data will determine the scope of work for the Transmission Rehabilitation program for the following year.

The Condition Assessment Program is a documented assessment of the transmission system facilities by a competent qualified utility employee who successfully completes the internal training. Assessments require a thorough inspection of overhead equipment to look for potential safety hazards to employees or the public, and risks to system integrity.

Power Line Technicians, with the help of a Designer (if required), complete the Condition Assessment and report deficiencies electronically consistent with the guidelines outlined in section 7 of this document. The Designer will then complete a Rehabilitation package to be given to the Project Management office to be scheduled into the following year's Rehabilitation program.

6. Annual Line Patrol Program Guidelines

The Annual Line Patrols consist of a drive by or fly by high level inspection of all the transmission plant every year. It is intended to identify failed and/or deficient equipment that occurred due to reasons beyond FortisBC control. These deficiencies are typically caused by vandalism, motor vehicle accidents, severe weather, etc. The patrols also identify unusual or new situations which may reduce line clearances, such as abnormally high water in boat or ferry areas, unusual/unfamiliar structures, signs of recent landscaping, changes in grade due to road or railway construction or maintenance, dirt or gravel heaps, buildings, grain bins, straw/hay stacks, etc.

On power line rights-of-way, items that require immediate attention include danger trees, gas storage facilities, and construction under power lines.

Power lines in the vicinity of airstrips and valley/water crossings must have marker balls installed. Unmarked or improperly marked power lines in the vicinity of airstrips and valley/water crossings must be assigned a high priority and corrected.

Stubs or poles left in ditches beyond the short window allowed during construction must be removed as quickly as possible depend on third party; this work will be dispatched through a capital salvage number.

Any energized or energizable points (i.e. equipment / conductors / terminals, etc.) or their enclosures, that are unlocked, damaged, open to reasonable public access, or otherwise unsafe, must be assigned a high priority and corrected immediately.

To ensure that two patrollers do not do a drive-by patrol on the same section of line, it is up to the Network Services group to track and manage the execution of the Annual Line Patrols. Deficiencies observed during the patrol are going to be tracked and corrected using the Dispatch tool.

6.1 Deficiency Rehabilitation Budgets

The following is FortisBC criteria to determine if a project should be charged to capital or operating.

Capital Expenditures are expenditures in excess of $1,000 and that meet **all** of the following criteria:

1. Provide substantial benefits for a period of more than one year.
2. Extend the useful life of an asset or increase the capacity of an asset or increase the output efficiency or reduce operating costs (non-recurring expenditures).
3. Are held for use to conduct business/generate income.

It should be noted that the $1000 has to absorb the following costs;

- Labour
- Contract work
- Vehicle hours
- Materials and supplies
- Overhead

The following paragraphs summarize what deficiencies should be applied to which budgets.

Routine Maintenance Budget (Operating) – Any deficiencies severe enough to be unable to make it to the next Condition Assessment cycle (eight year maximum) and requires less than a $1,000 in value to repair.

Urgent Repair Budget (Capital) – Any deficiency involving failed equipment or equipment showing eminent signs of failure and requires more than $1,000 in value to repair.

6.2 Criteria for Annual Line Patrol

Examples of the deficiencies to be assessed during the annual line patrol are as follows:

Capital deficiencies:

- ❑ Equipment causing an immediate hazard to the public with high potential for failure
- ❑ Severely rotted/cracked poles/crossarms
- ❑ Salvageable equipment
- ❑ Line clearance (horizontal, vertical, phase to phase and circuit to circuit)
- ❑ Broken/damaged guy wires (consideration should be given as to whether the guy can be removed rather than repaired)
- ❑ Missing/broken ground wire. Report all copper theft to the FortisBC standards department (diststan@fortisbc.com).
- ❑ Physical damage
- ❑ Chipped broken insulators
- ❑ Straighten severe leaning poles in locations that are highly visible to public and could be a hazard due to the amount of lean.

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O&M deficiencies:

- ❑ Missing/broken guy guards
- ❑ Missing or badly faded switch number tags
- ❑ Loose or missing hardware or connections
- ❑ Equipment that is not secure (cabinets locked)
- ❑ Missing signs/tags

The foreman should decide which of the two budgets (O&M, Urgent Repairs) should be applied to correct the deficiency and get an order number opened and dispatch started.

6.3 Safety Hazards Encountered During Patrols

Hazards encountered that pose a danger shall be handled as follows:

Immediate Danger

Safety hazards that could pose an immediate danger require the patroller to remain on site and secure the area affected by the danger.

The patroller shall take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If assistance is required, the patroller shall remain on site until qualified assistance or relief arrives.

No Immediate Danger

Safety hazards encountered that do not pose an immediate danger require the patroller to document the hazard and take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

6.4 Access Restrictions to Facilities

If access is restricted or the patroller is prevented from accessing, inspecting or maintaining facilities due to development (e.g. construction of a fence, building or driveway; planting of trees) report the condition to Operations Foreman to advise the customer.

Report any problems regarding vegetation to the Right of Way Supervisor (e.g. vegetation prohibiting access, insufficient clear distance for operating equipment on the system). Clear away any vegetation that is easily removed. See section 8 for more information.

7. Condition Assessment Program Guidelines and procedure

The Condition Assessment guidelines are broken out into each individual component throughout the following sections. There are guidelines described outlining what is an urgent priority, to be done right away using the Urgent Repair budget, and what is a rehabilitation deficiency to be completed in the following year's Rehabilitation budget.

For all transmission lines with distribution underbuild the distribution circuit is to be assessed as part of the transmission Condition Assessment using the criteria outlined in 801-02 (Distribution System Programs).

7.1 Pre - Condition Assessment Data Collection

Prior to assessing a transmission line a review should be done to;

1. Determine problematic areas of the circuit that has repetitively caused outages/urgent repairs

2. Determine any problematic areas that are repetitively causing O&M issues.

7.2 Pole and Crossarm

Refer to Appendix 1, M10-04 FBC In-Service Wood Pole Inspection and Re-Treatment for information on above ground and below ground inspections of wood poles and the criteria for stubbing or replacement. For multiple pole structures, use one assessment record sheet per pole.

All results from the wood pole inspections and treatment needs to be entered into ArcFM (GIS) to flag red and blue tagged structures to ensure the Condition Assessment personal address the issues.

For cross arms requiring replacement, note the type of arm required and other material required because the FortisBC standard cross arm will not cover all applications.

Fire damage on the lower body of the pole is normally caused by grass or brush fire and is usually only superficial. However, if the damage appears to be significant, remove the burnt wood and determine the extent of the damage. Fire damage high on the pole is normally caused by lightning or electrical current from a contaminated or leaking insulator. If structural integrity of the pole is suspected, report under “replace pole” and add the comment “fire damaged”.

Untreated poles should have a pole bandage applied as soon as possible after discovery.

7.3 Insulation

If insulation is inadequate or in poor condition (cracks, chipped, etc), then new insulation should be recommended.

Ohio Brass insulators have created problems on the system due to growth in the cement. The manufacturer's stamp normally identifies these components. Replacement of Ohio Brass insulators should be prioritized based on their location (i.e. a high priority given to Ohio Brass insulators in areas with a high risk of public line contacts).

7.4 Conductor Ties

Rust on an insulator may be an indicator of a broken or worn preformed tie and possible damage to the conductor and/or insulator. Closer visual may be required to see if the insert is missing or confirm if tie is broken or wearing.

A broken or rusted conductor tie may be an indication of other problems (e.g. sag too tight, damaged conductor).

7.5 Grounding

Ensure grounds are not missing, broken or excessively corroded. The case ground is attached on transformers; ensure ground wire is not broken or disconnected.

Check and repair connection between ground rod, connector and ground wire. Ground rods must be installed at every transformer/equipment pole and/or every third pole with no equipment attached.

FortisBC practice is to bond and ground all 138 kV and 230 kV structures. For 63 kV structures bond all hardware within 150 mm of one another, do not ground. Bonding and grounding is required on 63 kV structures **only** when there is underbuild or an overhead shield wire present

7.6 Guys and Anchors

When replacing a pole or an anchor, measure distances of any anchors from pole (make plan view sketch showing anchor locations and taps).

Prior to doing repairs on or around a guy wire, complete a thorough inspection to identify hazards that could result in mechanical failure or electrical shock. Assess the risk that a guy assembly has on the public and employees. Line clearance, pole lean or damage, or other hazards associated with broken guys or pulled anchors must be considered and fully noted on ArcFM (GIS).

If failure of the guy wire could result in electrical shock hazards, do not repair or work on guy assemblies with the circuit energized.

The guy wire types should be recorded along with the type of guy strain insulators and preformed grips. If the equipment sizes do not correspond, the equipment should be replaced with the proper sizes.

Insulation must be added to a guy wire if the attachment point of an un-insulated guy wire on a non-metallic pole or structure is located above energized primary components. The action is to be recorded in ArcFM (GIS) as “medium priority”, required action is “repair guy”, and insert “add guy link” in the comments section. When installing the insulation, it must extend from the attachment to a point below the lowest energized line. For example, if a structure has transmission with distribution underbuild, the insulation must extend from the attachment to a point below the distribution underbuild.

The preferred method to add a guy strain insulator to an existing guy wire is to de-energize the line

A guy strain insulator should be added if the anchor head is buried and the guy wire is above a primary and is in a location where by digging out the anchor still leaves a situation where the water cannot drain away.

When assessing anchoring, patroller should note whether the anchor is screw or plate type and also the anchoring distance (or lead length with slope). If multiple anchors are present, patroller should ensure adequate spacing between anchors (~3 metres) to ensure soil integrity.

If there is a need to have an anchor dug out, insulated, or extended in order to maintain the line integrity, record these as a “medium priority”, action required is “repair guy” and describe the requirement in the comments section. Record guys requiring replacement in ArcFM (GIS) as a “medium priority”, action required as “replace guy”.

Guying attachments on poles should be inspected to ensure the hardware is tight. Patroller should take note whether the guying attachment on pole is digging into wood, splitting the pole or whether the attachment is sideways.

The eye of the guy rod should be exposed above grade if it is not add a guy extender of sufficient length to expose the eye.

Guy guards are to be installed during the annual line patrol and corrected but if missing/damaged guy guards are identified then they should be noted and installed/replaced. If multiple guys go to one anchor then guy guards only need to be installed on the outer two guys.

7.7 Conductor

Conductors that need to be re-tied or re-sagged should be noted and corrected.

Bird nesting, broken strands or pitting on conductor or problems with sleeves, noting phase(s) and location of the problem spots must be reported.

Be aware of other conductor conditions that could compromise safety of affect line integrity (e.g. circuits constructed under or crossing under other circuits where both circuits are not supported on the same structure).

7.8 Clearance

Be alert for unusual or new situations which may reduce line clearances, such as abnormally high water in boat or ferry areas, unusual/unfamiliar structures, signs of recent landscaping, changes in grade due to road or railway construction or maintenance, dirt or gravel heaps, buildings, straw/hay stacks, etc.

In order to ensure accurate measurements all clearance issues must be recorded electronically to capture the information outlined in Appendix 2.

8. Vegetation and Osprey Nest Notification

8.1 Vegetation

Unwanted vegetation has the potential to adversely impact FortisBC's electrical infrastructure, threaten the safety of employees and the public as well as reduce system reliability. Accurate identification of unwanted vegetation on or adjacent to FortisBC's power system enables the Company to better understand growth rates and characteristics, predict locations and determine whether or not control is warranted or desirable. By understanding the vegetation along its power line corridors, FortisBC has a better appreciation of the types of control methods needed and the appropriateness of application. FortisBC uses tree risk identification and evaluation processes to make decisions regarding what potential hazards and vegetation threats may be associated with a particular tree or groupings of trees.

Monitoring vegetation and hazard trees is an essential planning and prevention element of the FortisBC Vegetation Management Program. Results from both the Annual Line Patrol and the Condition Assessment program are used to determine what actions are required to minimize risks associated with the possibility of vegetation coming into contact with power lines. If there are hazard trees identified or vegetation encroaching on the lines from either the Annual Line Patrol or Condition Assessment program then the location should be reported to the Right of Way Maintenance Supervisor using the Vegetation Notification Form.

The Vegetation Management Program, which is separate from both the ALP and Condition Assessment Program, will include both ground and air patrols of FortisBC's Transmission Networks as outlined in the FortisBC Vegetation Management Program.

8.2 Osprey Nest

Ospreys frequently build nests on transmission poles. Bird contacts on transmission lines/equipment can cause outages. These outages create momentary interruptions and a higher risk of long-term interruptions when they occur on main lines.

If there is an Osprey nest identified that is encroaching on a Transmission line from either the Annual Line Patrol or Condition Assessment program then the location should be reported to the Environmental department and tracked in Arc FM (GIS).

9. Reporting Structure

9.1 Capture the Information

All information (Test and Treat, Condition Assessment, Annual Line Patrol) obtained in the field will be entered, in the field, with the use of a computer. The computer program has to gather all the required information and transfer that data daily (if a network connection is available) into the FortisBC ArcFM (GIS) software.

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9.2 Required Information

Having sufficient information available for all transmission assets is beneficial from an operational, engineering, and planning perspective. The following bullets outline the minimum requirements for each type of patrol;

ANNUAL LINE PATROL

a. Area patrolled.

b. Date Annual Line Patrol person was on site.

c. Who did the Annual Line Patrol

TEST AND TREAT

a. Pole shell thickness and actions required (Replace urgently, Red Tag, Blue Tag) as per Appendix 1 (M10-04, FortisBC In-Service Wood Pole Inspection and Re-Treatment).

b. Type of fumigant(s) (rot/insect) added to the pole.

c. Date test and treat person was on site.

d. Who did the test and treat

CONDITION ASSESSMENT

a. Enter the corrective standard structure(s) and/or material to remedy the overhead/underground deficiency, for example, 4230-5, 5010453, etc.

b. Enter a rating between 1 and 4 for the Crossarm and Pole.

1 -	Fail -	Urgent Repair
2 -	Poor -	Include in Rehabilitation package
3 -	Fair -	Will last another eight year cycle

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4 - Good - Will last multiple cycles

Note: The rating system is in place for planners so they can determine how many structures are going to fail during the next rehabilitation cycle. For example; if the assessor's best judgement outlines that the pole will last one more cycle (8 years) but will not last two more cycles, the pole will be flagged as a "3" and will probably be replaced in the following rehabilitation cycle. Having this information available during the planning stage of the project will allow planners to determine more accurate budgets for the rehabilitation program.

c. Enter already established units for how the pole will be set, i.e. blasting, back hoe, crane, hand dig, etc.

d. Enter if flaggers are required to replace the pole.

e. Enter if work can be done hot or cold.

f. Enter if environmental considerations are required.

g. Enter if a special permit is required for work.

h. A comment box is required to communicate certain things from the field to the designer such as anchoring and sag specs, ground clearance problems, etc

i. Who did the Condition Assessment.

j. The date the Condition Assessment was done.

9.3 Deficiency Tracking and Updating

Once the deficiencies for the asset have been remedied, the As-built process will need to be adjusted such that the deficiency information is removed from ArcFM (GIS) and no outstanding actions are reported for that asset.

All other information from this process will remain in the system until the next Condition Assessment cycle at which point it will be overwritten.

9.4 Reporting

At any time a report from ArcFM (GIS) can be generated between two points or for the entire transmission line outlining;

a. A structure by structure list of outstanding deficiencies, as outlined in section 8.2 under Condition Assessment such as crew hours, equipment required, material, flaggers, special comments, etc.

b. Historical information for planning purposes. The following should be tracked and able to report on a feeder by feeder basis: Shell thickness, vintage of all poles, and how many of them were replaced or stubbed in previous rehabilitations. This will help planners determine better budgets for upcoming years' rehabilitation.

c. A Line summary report of deficiencies outlined as urgent repairs or rehabilitation.

d. A Line summary report on an annual basis to display equipment replaced during any given years' rehabilitation.

e. A Line summary report with treatment type, units, quantity inspected

9.5 Rehabilitation Package

The Rehabilitation package will be prepared by engineering and will be laid out as follows:

- Project Work Summary
- Project Estimate

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- Project Bill of Materials
- Third Party Cost Summary (excavation, blasting, flaggers, etc)
- Standard and Non-Standard approved drawings
- Structure Location Map
- Structure Details

Each structure detail will have one, 8.5”X11” page per location and include the following:

a. Pole identifier with XY coordinates
b. A route map to get to the pole
c. A Bill of Material and costs of material
d. A work summary/comments from designer
e. Crew hour summary
f. Equipment summary (hoe, crane, blasting, etc)
g. As-built template and commenting section on back of sheet
h. Picture if easily implemented
i. Designer’s name
j. Date design package was completed and issued
k. Permits/notifications (customer, Ministry of Transportation, flagging)
l. Revision tracking area

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10. Vegetation Notification Form

Customer Name: ______________________ Date ____________

Address: ______________________________

Phone Numbers: Home ______________ Business ______________

Location of tree(s) causing concern:

Assessing Vegetation Control Responsibility:

Type of circuit affected: ☐ Secondary or service conductors ☐ Primary (distribution) ☐ Primary (transmission

Is the tree (s) located on:

☐ Customer's (private) land
☐ Other's private land
☐ Public land (e.g. MOH, Crown ______________

Is the tree (s) affecting:

☐ Existing FortisBC facilities ☐ New Construction ☐ Customer-owned facilities

Referring to the table summarizing responsibility for vegetation control, the tree control responsibility is:

☐ - the customer or facility owner's or
☐ - FortisBC or
☐ - a field check is required for clarification

Advise the customer of trees that are the customer's responsibility to control. For trees that are FortisBC's responsibility to prune or remove, or that require a field check, forward the completed form to vegetation management personnel. Advise the customer someone will investigate the problem.

* Table summarizing responsibility for vegetation control:

	Type of Circuit	
	Primary	**Secondary**
Existing Facilities		
* Private Land	FortisBC	Customer
* Public Land	FortisBC	FortisBC
New Construction (initial clearing)		
* Private Land	FortisBC	Customer
* Public Land	FortisBC	Customer
Customer-owned Facilities		
* Private Land	facility owner	facility owner
* Public Land	facility owner	facility owner

Action taken (see notes on the bottom of this form):

☐ Customer advised tree control is the customer's responsibility (no further action required); or
☐ Form directed to vegetation management personnel for further review.

For tree problems that require further review:

Customer contacted by: ______________________ On (date): ________
Site visited by: ______________________ On (date): ________
Action required: ______________________________

Problem resolved by: ______________________ On (date): ________

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11. Definitions

Apparatus: In ArcFM (GIS), apparatus include transformers, capacitors, and all oil-filled equipment.

Corrective Planned Maintenance: Maintenance performed to bring an asset back to standard functional performance. Trigger by predictive maintenance.

Device: In ArcFM (GIS), devices include bypass switches, cutouts, airbreaks and modular oil-filled switching terminals (MOST).

Emergency Corrective Planned Maintenance: Maintenance performed to bring an asset back to standard functional performance requiring immediate corrective action. Trigger by predictive maintenance to address safety, environmental, or economic risk caused by equipment breakdown.

Exception Reporting: Reporting only information or data that is outside a defined set of parameters for a specific piece of equipment or system.

Known Defects: Identifying equipment or systems that may be potential causes of failure based on information received from manufacturers, other utilities or outage statistics.

Predictive Maintenance: Visual inspection of facilities taking measurements and observations of components or systems. Interpreting and acting on the results by initiating corrective planned or emergency maintenance.

Qualified Employee: means a power line technician trained and experienced to work safely on energized electrical equipment or lines in accordance with the requirements of the safety rules while performing duties assigned by an employer.

Rehabilitation: Corrective planned maintenance required within 2 to 12 months to address concerns that will be a safety, environmental or system concern prior to the next patrol or inspection

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Special Requests: Information required by maintenance planning on a one-time basis due to special circumstances, data requirements or for bundling of tasks for cost effectiveness.

Supporting Structure: In ArcFM (GIS), supporting structures include poles, pedestals, vaults, standards, and all hardware attached.

Urgent: Emergency corrective maintenance that must be done immediately to care for safety, environment or system integrity. The completion of high priority repairs is the accountability of Power Line Technicians. If the patroller cannot correct the deficiency immediately, it is the patroller's responsibility to communicate the deficiency to Dispatch. Maintenance work that has been completed must be documented in ArcFM (GIS).

Appendix 1

FortisBC Wood Pole Testing and Re-Treatment, In-Service Document

FortisBC

Wood Pole Testing and Re-Treatment In-Service

Based on Wood Pole Pest Management Plan under the Integrated Pest Management Act

Table of Contents

1.0 Introduction

The testing and treatment of wood poles involves an evaluation of the integrity of the pole's physical characteristics and serviceability despite deterioration or damage, and taking measures to prolong the service life.

FortisBC has two main treatment groups of poles in service.

a) **Full Length Treated** – where the whole shell of the pole has been impregnated with Pentachlorophenol (Penta) or Chromated-copper-arsenate (CCA) preservative. The species of poles usually treated under this treatment group are: Western Red Cedar, Lodgepole Pine and Douglas fir.

b) **Butt Treated** – where the butt of the pole (including 0.6 m to 1.2 m above ground line) has been impregnated with Creosote or Pentachlorophenol (Penta) preservative. Incising is often part of the treatment. The species of poles treated under this treatment group is usually Western Red Cedar.

Untreated poles can also be found in the service area.

Decay fungi (i.e., plants that feed on wood) can destroy the structural integrity of wood. Fungi require water, air, favourable temperature, and food in order to propagate and survive. Wood with moisture content below 20 percent usually is safe from fungi. When wood is submerged in water or buried deep in the ground, air is eliminated and fungal growth is minimal. Freezing temperatures stop fungal growth but seldom kill it.

The service life of wood poles is influenced by many factors such as wood species, initial preservative treatment, climate, location, and maintenance practices.

- <u>Full-length treated poles</u> generally suffer little decay during the first 20 years of their life.
- <u>Butt treated poles</u> show signs of decay on the untreated shell earlier than the full-length treated poles (15 years).
- <u>Untreated poles</u> have a considerably shorter life span than the full-length and butt treated poles. An untreated pole could decay at the ground line in 5 to 10 years.

1.1 Scope

This document outlines requirements and guidelines for inspecting and retreating wood utility poles owned or maintained by FortisBC.

1.2 Using This Document

It is the responsibility of persons using this document to seek clarification, where needed, from the Maintenance Planner.

2.0 Benefits of Pole Testing and Treatment

At regular intervals, FortisBC conducts testing and treatment of all in-service wood utility poles that are owned or operated by FortisBC.

The benefit of maintaining wood poles is to extend their service life, thereby minimizing costly replacements. The testing and treatment methods used are designed to ensure public and employee safety, provide appropriate reliability, and prevent high consequence failures.

3.0 Maintenance Policy for In-Service Poles

3.1 Inspection

In-service wood poles shall be periodically inspected and maintained. Poles 16 years of age and older will be inspected as outlined in this document and, if necessary, will receive remedial treatment as outlined in this document. Poles newer than 15 years of age will only receive an aboveground visual inspection (refer to section 5.3) unless extraordinary conditions apply. Reliability-centred maintenance principals of tracking degradation within a species, treatment, service territory, or maintenance program may alter inspection cycles to be more suitable and cost-effective. Recommend treating all non cedar poles with in 8 years, new poles may show signs of decay before 15 years because they are second growth. Growth rings are further a part.

3.2 Maintenance Cycle Requirements

All inspected poles shall receive a full inspection that includes, but is not limited to:

- Visual inspection
- Sounding
- Drilling/boring

The contractor shall determine the appropriate remedial treatment based on the specifications outlined in this section.

4.0 Roles and Responsibilities

The key personnel involved in FortisBC's Pole Testing and Re-Treatment program are the Maintenance Planner and Pole Inspection Contractors.

4.1 Maintenance Planner

The Maintenance Planner is accountable for the development and general administration for the In-Service Wood Pole testing and Re-Treatment program.

The primary responsibilities associated with administration for the In-Service Wood Pole testing and Re-Treatment program are:

- Coach Line Construction Manager and inspection contractors on standards to work to
- Combine and develop budgeting and work plan submissions
- Ensure communication of work planned and completed
- Pre-qualify inspection contractors and tender contracts
- Hold relationship with contractor management
- Verify that the inspection contractors carry out the duties within their contract with FortisBC
- Dispute and work quality resolution with Line Construction Managers, and inspection contractors
- Accountable for incident investigation and reporting
- Review program standards and procedures

4.2 Line Construction Manager

The Line Construction Manager ensures the maintenance of in-service wood poles in a condition that supports reliability, integrity and safety. This is accomplished using contracts and contractors performing accepted inspection and test methods.

Line Construction Managers verify contractor hours and units reported, aid in customer contacts, and resolve customer complaints and damage claims. Line Construction Managers also assist with identifying work areas and scheduling of crews.

Specific to the monitoring of the pole test and re-treatment program, the Line Construction Manager must:

- Have knowledge and/or experience in the following areas:
  - Powerline operations and electrical safety
  - Contract Management
  - Customer/ stakeholder dispute resolution
  - ArcFM
  - Safety procedures and audits
  - Internal wood Pole testing and Re-treatment documents (e.g. this document)
  - Acts, regulations and company policies and procedures governing pole testing and re-treatment work
  - Inspection crew capabilities
  - Access requirements for working in and around gas installations

The primary responsibilities associated with the Line Construction Manager with respect to the pole test and re-treatment program are:

- Ensure contractors work in safe manner meeting both FortisBC and government regulations
- Ensure the necessary permits, licenses, or permissions are obtained for entering onto property to conduct pole inspection and testing work
- Notify county, municipal or regional district authorities and owners of work planned for their jurisdictions.
- Perform safety and work quality audits on pole test crews
- Audit the standards conformance and compliance of the inspection contractors to their contract with FortisBC
- Check and verify invoices
- Support incident and accident investigations and reporting relevant to pole inspection work performed for FortisBC
- Resolve customer inquiries and complaints regarding pole inspection, testing and re-treatment
- Maintain working relationships with internal stakeholders including Network Services Native reserves

4.3 Inspection Contractors

Work for inspection contractors is identified within ArcFM. The work is normally paid on a unit price basis.

When an inspection contractor moves into a new area, they should make the opportunity to meet the local contacts.

Crews submit a weekly update of the units completed to the Maintenance Planner. Contractor personnel enter the date completed on ArcFM for locations completed that day and send ArcFM packets on the completion of an RCM circuit to the Maintenance Planner. Send in on completion of area

4.3.1 Contract Adherence

The Contractor must adhere to the Wood Pole Test and Treat Agreement contract at all times. Failure to comply with any of the requirements of the contract without prior authorization will result in a crew warning or shutdown.

4.3.2 Crew and Equipment

The Contractor assumes the full responsibility for having the proper equipment required by the federal, provincial and local laws for the work covered by the contract. The Contractor is also responsible for meeting all safety regulations.

The Contractor is responsible for ensuring that their personnel are familiar with this manual, all safety legislation, and any other pertinent acts that may apply to their work. FortisBC is not responsible for training Contractor crews, however, the Line Construction Manager or Maintenance Planner can be contacted to clarify any matters.

The crews must be courteous to customers and quickly process any inquiries, complaints, or damages according to the proper procedures.

4.3.3 Standards of Work

Inspection contractors are accountable to ensure they have the appropriate permissions and approvals to undertake inspection activities. Approval to do the work is given by FortisBC, with contract specific requirements for obtaining individual access.

The contractor is responsible for identifying any potentially hazardous situations and using good judgement to avoid them.

4.3.4 Obtaining Licenses and Permits

The contractor is responsible for obtaining all licenses and permits required for performing their work. The contractor is responsible for knowing which permits are required and for ensuring permits are in place before commencing work. All conditions of the current Wood Pole Maintenance Pest Management Plan and permits are to be followed. Use records and annual report submission shall be submitted to FortisBC Environment by December 31 of the treatment year in accordance with Section 39 of the IPM Regulation.

Inspection contractors are accountable for having the proper personnel licenses required by federal, provincial, and local laws for the work covered by the contract.

The contractor is responsible for obtaining permits not directly related to inspection work (for example, load or road permits, and municipal dumping permits).

4.3.5 Minimum Competency for Pole Testing and Treatment Application

The minimum qualifications for individuals undertaking pole test and re-treatment will be approved by the Line Construction Manager but should include:

- Prior experience working under a competent tester prior (e.g. evaluating a minimum of 5000 poles under the direct supervision of a competent tester) 6-8 months
- Knowledge of the requirements of this document, the Pole test and Treat Agreement, and applicable regulations
- Knowledge of Provincial and Federal legislation for pesticide transportation, storage, handling, application, and use pesticide applicator certificate

5.0 Inspection Procedures

This section describes the procedures to be followed by trained personnel doing maintenance inspections of in-service poles and stubs. The inspections include the following: above ground inspection, partial below ground inspection or full below ground inspection. The requirements in of when to replace or stub a pole are also included in this standard.

Strength calculations, outlining mathematical calculations to determine pole integrity, are covered in Section 5.3. As well, the application of external and internal treatments is covered in separate sections.

5.1 Safety Hazards Encountered During Pole Testing and Treatment Program

Perform a visual inspection while approaching each pole, and while working in the vicinity of the electrical system, to detect possible safety hazards, including broken insulators, loose wires, loose or broken guy wires, leaning poles, broken ground downleads (COULD BE ENERGIZED), or “Hot” poles due to insulator leakage.cut outs

Hazards encountered that pose a danger shall be handled as follows:

Immediate Danger

Safety hazards that could pose an immediate danger require the pole inspector to remain on site and secure the area affected by the danger.

The pole inspector shall take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If assistance is required, the pole inspector shall contact the PIC or the Line Construction Manager and remain on site until qualified assistance or relief arrives.

Danger Pole

Poles that are not an immediate hazard but suspected of failing within one year must be reported to the Line Construction Manager And the contractor delegate

No Immediate Danger

Safety hazards encountered that do not pose an immediate danger require the pole inspector to take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If other resources are required to eliminate the safety hazard, the pole inspector shall document the hazard in ArcFM, and contact the PIC as soon as practically possible, relaying details of the hazardous situation.

Other deficiencies not considered to be a safety hazard shall be noted in ArcFM, as covered in this document.

5.2 Preparation

When work is to be done in close proximity to a home or on private property, the property owner shall be notified as to what is being accomplished. Brush will be removed from around the pole to allow for proper excavation and inspection, unless the property owner denies permission for removal. If permission is not granted, the pole will be sounded and bored, and reported.

CAUTION: Care must be taken to ensure the ground wire is not broken, and not to break the ground wire or to disconnect it from the ground rod. Ground wires must be carefully pulled away from the pole so as not to interfere with the work and restored to original location when work is completed.

5.3 Above Ground Inspection

An inspection of all poles shall be made from the ground line to the top, before excavating for the below ground line inspection.

Above ground inspections include:

(i) visual inspections to identify:

- lateral breaks or cracks
- above ground decay pockets
- excessive spur cut
- woodpecker holes
- broken ground wires
- signs of insect infestation
- shell rot
- pole top rot
- rotten or split top
- physical damage
- broken crossarm or hardware
- fire damage cut outs

(ii) probing and sounding to detect internal decay;

(iii) drilling into the pole at ground line near the largest check, and at other locations where internal decay is suspected.

If the pole is obviously not suited for continual service due to excessive shell-rot or other serious defects, it shall not be excavated, but shall simply be reported as a reject and recommended for replacement. If judged serviceable, it shall be excavated and further inspected. Ground line is from the ground up to 12" above

This section is broken down into external and internal inspections.

External Inspections

External inspections are a visual inspection of the above ground zone of a pole or stub.

Defects that are too high up the pole to be properly inspected shall be documented in ArcFM, and so a follow-up inspection can take place by a person qualified to climb the structure and inspect the defect.

Visual inspections above ground identify the following defects:

- *Shell Rot/Damage*: Such things as shell rot, lightning damage, physical damage, and fire damage can significantly reduce pole strength. Poles shall be identified for replacement based on the presence of shell rot or damage if the following conditions are true:
  - Poles with a circumference greater than 1200 mm shall be marked and reported for replacement if shell rot or damage is greater than 50 mm deep for more than 30% of the circumference.
  - Poles with a circumference between 775 mm and 1200 mm shall be marked and reported for replacement if shell rot or damage is greater than 25 mm deep for more than 30% of the circumference.
  - Poles less than 775 mm circumference shall be marked and reported for replacement if shell rot or damage is greater than 13 mm deep for more than 30% of the circumference. Rare in FortisBC area
- *Breaks*: Lateral damage (a break) occurs when a pole is over-stressed (e.g., after being struck by a motor vehicle), and can render the pole unsafe. A cracked pole should be recommended for replacement and reported immediately to the Line Construction Manager.
- *Woodpecker damage*: Generally, small woodpecker holes, particularly those that follow checks, do not significantly reduce the strength of a

pole and do not have to be reported. A very large woodpecker hole, or several smaller woodpecker holes at the same general location can weaken the pole significantly, and may be an indication of insect infestation and/or unsound wood, and must be reported.

- *Insect infestation*: Insect infestation can be recognized by: obvious insect activity, piles of sawdust or sawdust-like material, round and oval holes on the surface of the pole, or galleries under the surface of the wood. Areas infested with insects shall be investigated by boring and probing

Internal Inspections

- *Probing*: Probing is used to detect decay in checks and pockets and can be done with a screwdriver or stiff wire. Rot should be suspected when wood yields after firm pressure is exerted on the wood within deep cracks and pockets. Suspicious areas shall be investigated by boring. **Note:** Jabbing sharpened bars into the surface of a pole or stub is not recommended as this may damage fungus resistant wood and allow rot to start in less resistant areas.
- *Sounding*: Sounding is used to detect internal decay of a pole or stub. Sounding shall be performed on all inspected poles. A hammer is used to strike the surface of the pole from the ground line to as high as can be reached. This shall be repeated for each quadrant of the pole. A sharp ring indicates sound wood, whereas a hollow sound or dull thud indicates hollow heart or decay. Seasoning checks, internal checks, and shell rot can affect the sound. Suspicious areas shall be investigated by boring.
- *Boring*: Boring is done to determine the condition of the inner wood. Holes should be drilled using a bit diameter that is suitable for the treatment that will be applied to the pole at the following locations:
  - for a stubbed pole: near the upper and lower bands or bolts in both the pole and the stub;
  - where sounding or probing indicates a possible defect;
  - at locations of insect infestations;

When boring takes note of:

- the rate of penetration of the drill: sudden collapse of the wood being drilled indicates decayed wood or hollow heart;

- powdery wood particles indicate insect infestation or dried out decay;
- discoloured wood particles (such as severe darkening) almost always indicates the early stages of internal decay; in the late stages of decay the wood may become soft and spongy, stringy or crumbly; care must be taken not to mistake sound wet wood for decayed wood, colour is a good identifier; sound wood usually has a clean, fresh, resinous smell; a musty or mushroom smell may indicate decay.

▪ *Shell thickness:* If internal decay is found above ground line by drilling, two additional holes shall be drilled, equally spaced around the circumference of the pole at the same horizontal plane. Shell thickness shall be measured through the inspection holes with a shell thickness indicator tool or other appropriate tool. Note the shell thickness measurements in ArcFM. Average shell thickness shall be determined using a minimum of three measurements taken along the same plane of reference on a pole.

- If average shell thickness is less than 2.5 cm (1 inch), the pole shall be marked and reported for replacement. 3"or less of shell above gl is a reject
- If average shell thickness is greater than 2.5 cm (1 inch) and less than 6.5 cm(2.5 inch) the pole shall be marked and reported for stubbing.3" to 1" below ground line is a stub Deep Decay poles are marked for stubbing
- **Note:** Poles must be appropriately internally treated when stubbed.

5.4 Below Ground Inspection

Note: Do not excavate around a pole if it is unsafe to do so (e.g., the pole is rotted through at ground line, or a pole is not set deep enough in the ground). The minimum setting depth is 10% of the pole height plus two feet. Unsafe poles shall be reported immediately to the Line Construction Manager.

Below ground inspections include:

a) excavating around a pole (as required for proper assessment and treatment of the pole);

b) probing and sounding to detect internal decay;

c) confirming internal decay by drilling;

d) drilling for internal treatment;

Internal Inspection

Note: All bored holes shall be plugged with a removable / reusable, brightly coloured, tapered plastic plugs with 1.5 mm interference fit, or approved substitute. The plugging of the holes is to reduce the possibility of the bored holes from serving as an entry where practical; drill holes from previous inspections are to be re-used as part of the following boring requirements: ¾ “ drill bits with 15” of shank

- A minimum of three holes shall be drilled in the following locations:
  - Poles and wood stubs shall have three divots dug, so that one inspection hole can be drilled at 30 – 38 cm below ground line and two inspection holes can be drilled at 7.5 - 15 cm below groundline. The holes shall be located 120 degrees apart in section at an angle of 45-60 degrees from the pole in profile.
  - Both the original pole and a wooden stub shall be drilled in the vicinity of either the upper and lower bands or bolt points.
  - Poles shall be drilled where sounding indicates a possible void.
  - Poles shall be drilled at locations of insect infestations.

5.5 Backfilling and Clean-Up

After inspection and treatment, the excavated area shall be refilled and firmly tamped to avoid the possibility of subsequent settling. Do not backfill loose articles, turf, garbage or loose asphalt. To prevent damage to the bandage, protect the bandage with a shovel during backfill.

No debris, loose dirt, etc. is to be left in pole area in the case of city or private property poles. Private property turf, bushes, etc. are to be replaced with care.

5.6 Identification and Tagging of Work Completed

Work Performed

All inspected poles shall be marked with a tag identifying the inspection company, and the year the work was completed. Tags shall be placed 2.1 m above ground line on the roadside of the pole. All tags shall be attached to the pole with screw shank aluminum roofing nails. Completed missing pole sheets and marked up maps are to be submitted to the

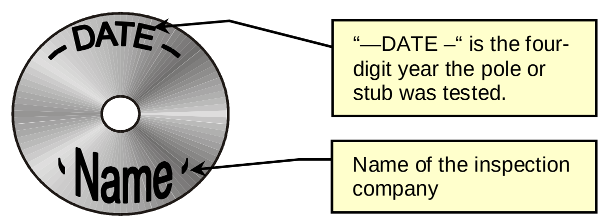
Senior Maintenance Planner as completed for data entry. Extra poles sheets

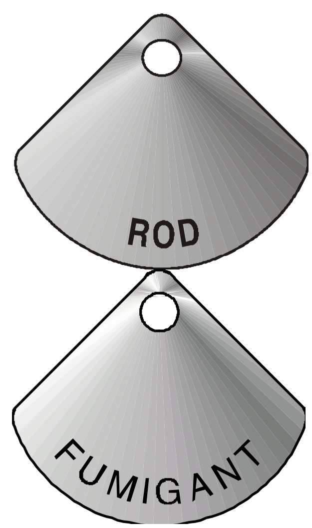
Rejected Poles

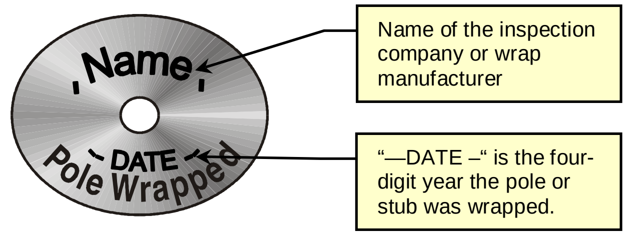
Poles that are recommended for replacement shall be identified by 3.8 cm red nylon webbing with white “XX” lettering, securely attached to the pole approximately 1.8 m above ground line. With a 3” -3” red square tag over the ribbon

Poles that are recommended for stubbing shall be identified by 3.8 cm red nylon webbing with white “XX ST XX” lettering, securely attached to the pole approximately 1.8 m above ground line. With a blue 3”-3” square tag over the ribbon

All inspected poles shall be tagged as outlined in this section. The tagging shape indicates appropriate pole condition and treatment.

Pole or stub was inspected:	

Internal decay, treated with Boron, CuNap, Fumigant: data is entered in arc fm	

Pole has been inspected, pole wrap installed at groundline: data is entered in arc fm	

Green 3"-3" square tags mark No Treatment Zones

Pole requires replacement, **DO NOT CLIMB:**

Pole must be stubbed. Pole found to be weakened due to rot, insects or mechanical damage. **CLIMB ONLY IF SUPPORTED:**

The pole tester also marks poles identified for replacement or stubbing with a 7.62 cm by 7.62 cm colour-coded plastic tag. Tags are nailed to the nylon, on the side of the pole normally visible to an approaching line worker.

<u>Colour-coding for pole stubbing or replacement tags:</u>

The following colour coding is used on the 7.62 cm by 7.62 cm colour-coded plastic tags, supplied by the Maintenance Planning and Brushing group:

Tag Colour	Tag Installation Year	Year Stubbing or Replacement to Occur
Red replace		
Blue stub		
Green ntz		

Note: There may be tagging outstanding from earlier pole marking programs.

6.0 Pole Treatment Application

If the pole is serviceable, pesticide treatments are used to remediate existing as well as prevent further structural damage caused by wood rot and wood-boring insects and fungus. This includes poles identified as requiring stubbing.

Required remedial treatments are based on the condition of the pole and on the pole vintage.

External treatment involves the application of a partial (18" wide) or full (24" wide) preservative bandage below the ground line. The ingress of fungus and insects into the poles is prevented using this treatment type. Does very little for internal decay

Internal treatment is applied to poles to arrest internal decay or exterminate insects. Holes are drilled in the sides of the pole above and below ground. The internal treatment is applied by injecting or inserting the chemical into the drilled holes.

All chemicals used on, or in, FortisBC power poles must be registered for use in Canada by Pest Management Regulatory Agency (PMRA), and approved by FortisBC, as for use on wood products as listed in the current Pest Management Plan. Follow manufacturer's instructions. Refer to Appendix A for a listing of currently approved preservative bandages, remedial treatment rods, fumigants, cavity floods, and insecticides.

6.1 Bandage Treatment (External) Treatments should not be determined by the poles vintage

External groundline treatment shall be performed as follows:

- **Poles of 1959 vintage and older:** Poles of this age shall not receive any external ground line treatment.
- **Poles of 1960 - 1979 vintage:** Poles of this age identified by the inspection program, shall receive an external ground line treatment. CCA-treated poles do not receive the external ground line treatment unless there is evidence of decay.
- **Poles 16 years old to 1980 vintage:** Poles of this age shall receive an external ground line treatment only if the shell is "punky" or showing signs of shell rot at the ground line.
- **Poles 15 years and newer:** Poles in this range shall not receive external ground line treatment unless extraordinary situations apply.

6.2 Internal Treatment

Internal treatment shall be applied as follows:

- **Poles 16 years old and older:** Install remedial treatment rods and borate-based liquids (not copper napthenate) at the same time only if the pole has moisture content of 25% or greater. Fumigate if the pole if the moisture content is below 25%. All poles of this vintage shall receive remedial treatment. If a void is present one of the following shall be performed:
  - o Liquid wood preservative (cavity floods) shall be flooded directly into the void until the cavity is full.
- **Poles 15 years and newer:** Poles of this age shall not receive internal inspection unless extraordinary conditions apply.

7.0 Legal and Other Requirements

The following list provides a summary of some of the acts, regulations, standards, and practices that affect pole inspection work:

- Integrated Pest Management Act
- BC Transportation Highway Accommodation
- Agricultural Chemicals Act
- Clean Water Act
- Code of Practice for Watercourse Crossings

- Environment Code of Practice for Pesticides (ECPP)
- Forest and Prairie Protection Act and Regulations
- Land Surface Conservation and Reclamation Act
- Occupational Health and Safety Act (OHSA)
- Pest Control Products Act
- Pipeline Act
- Transportation of Dangerous Goods (TDG) Act and Regulations
- Transportation of Dangerous Goods Control Act
- Weed Control Act

8.0 Reporting – Using ArcFM

The attributes, testing, and treatment information for all inspected poles shall be recorded, updated, or confirmed in FortisBC Corporate Mapping System (ArcFM Mobile).

Contractors are expected to perform the follow tasks in ArcFM Mobile:

- Update basic pole information including: Pole Stamp Date, Height, Class, Species, Type (Transmission/Distribution), Material (Wood, Steel, Concrete), usage type (Secondary, Primary) and Pole Treatments.
- Identify any required and completed actions
- Update inspection information regarding test results of the pole including Circumference, Shell Thickness (East, South and North Face) and any comments

Contractors are expected to keep a listing of all mobile sessions submitted to FortisBC for processing and are to ensure naming of mobile sessions is clear and descriptive.

Contractors are expected to follow the procedures outline in “Inspection (pole and Line Patrol) ArcFM Mobile Workflow” for updating information in ArcFM mobile.
FortisBC will supply the contractor with the necessary software to run reports on completed sessions before the sessions are submitted

Reasonable justification shall be given, in the comments section, whenever a pole that has been specified by FortisBC for inspection may not be tested or treated. Justifications include:

- pole has no FortisBC equipment on it;
- pole is commercially butt treated and less than fifteen years old;
- pole is in water;
- pole is inaccessible.

No treatment zones
Difficult digging due to brush or roots does not warrant deferring inspection or treatment.

Any poles not scheduled for testing, treatment, but obviously requiring inspection should be inspected. For example: poles in the test / treat age group not shown on FortisBC maps; poles affected by grade changes; and poles affected by vehicle damage. Insect damage, checks

8.1 Creation of Sessions

- A new session must be created at minimum of once per day.
- A new session must be created if the computer crashes or other odd behavior is experienced.

8.2 Submission and Syncronization

- Contractors receive the ArcFM Mobile application and are required ensure that information is uploaded and downloaded from ArcFM Mobile machines at a minimum of a weekly basis to ensure that the data on the mobile machines is current and that information collected on the mobile machine is sent to FortisBC. This will require that the contractor connect to the FortisBC computer network at one of the FortisBC offices in the service area.

8.3 Setting Work Order Information

- All edits in ArcFM are tracked to a workorder that identifies the job and to a salvage workorder which allow assets to be removed from FortisBC's asset base. FortisBC project managers should provide a listing of workorders for the job

8.4 Indicating Poles and Pushbraces Need to be Removed

- Sometimes people will come across poles or pushbraces that exist in ArcFM but do not exist in the field. When this is found the users are expected to identify the poles that do not exist so that they can be removed properly from the FortisBC system. This is accomplished through simple map markups using ArcFM Graphics

8.5 Adding a Missing Distribution Pole, Pushbrace or Transmission Pole

- If a pole is found in the field during the audit and is not found in the mapping system, it can be added and related records added and inspection conducted to the pole to ensure that all pole and related information is complete. Also, pole inspection information may be added to the pole as well.

9.0 Monitoring, Measuring, and Continual Improvement

9.1 Monitoring

IPM Regulation requires a monitoring program to evaluate the effectiveness of the pesticide use under S 58(f). Section 69.(2) requires pre-treatment and post treatment observations of the treatment area to evaluate the effectiveness and impact of each pesticide use.

The following monitoring methods are undertaken to control critical activities:

Aspects and Critical Activities	*Monitoring Method*	*Primary Responsibility*	*Monitoring Frequency*
Pole integrity evaluation	• DOSS • Incident database • ArcFM	• Maintenance Planner	Ongoing
Pole testing / re-treatment	Field audit	Line Construction Manager	Weekly during contract term
Pesticide application and handling	Visual audit	Line Construction Manager	Weekly during contract term

9.2 Auditing

The Line Construction Manager performs safety and work (quality) audits on inspection contractors.

9.2.1 Inspection Contractors

Inspection contractors receive:

- A detailed audit twice per year: one at start-up and one part way through the contract term (e.g. truck, equipment, tools, qualification of employees)
- A work observation audit (drive-by) at a minimum every two weeks (observe work methods; check for safety items like shields, hard hats, safety glasses). Drive-by audits are not announced.

Quality of work is checked including:

- Compliance with contract and program requirements
- Use of proper techniques and practices
- Proper clean-up of area
- Records completed

Contractors expected to audit their crews regularly (every two weeks) and supply a copy of the audit results to the Line Construction Manager. Audit areas upon completion 2%

9.2.2 Corrective Action

The Line Construction Manager advises the audited party of any nonconformance.

9.3 Continual Improvement

The Maintenance Planner and Line Construction Manager regularly discuss the program, and resolve issues, ensure consistency (where it makes sense to do so), and continually improve processes. Meetings are held with contractor personnel prior to start-up and at the end of the contract period to ensure efficient and effective contract execution.

9.3.1 Inspection Contractor Start-up Meetings

A meeting is held prior to the start-up of a new pole test and treat contract (at no cost to FortisBC). The meeting is held to ensure clarity on the contracted work prior to the fieldwork being initiated. Key topics of concern to both parties are discussed, and time is made available to answer questions or discuss issues raised.

Topics covered could include:

- Goals of FortisBC's pole test and re-treatment program
- Contractor accountabilities
- FortisBC's Health and Safety Policy
- Safe Work Planning, Safety, and Incident Reporting
- Work packages – the information provided to the crew
- Standards and specifications
- FortisBC operations contacts

10.0 Record Location and Retention

Record retention shall be in accordance to FortisBC's record management policies. The chart below summarizes records that may be generated from the pole test and re-treatment program, and provides a retention classification code that corresponds to the records classification system retention schedule.

Records	Location of Records	Retention Classification Code(s)
FortisBC one-Call	Line Construction Manager's files	
Damage claims		
DOSS reports (vegetation contacts causing outages)	DOSS database	
Pesticide application logs	Contractor's files,	
Pesticide licenses and permits	Contractor's files, if required	
Pesticide spill reports	Contractor's files	
Pesticide transportation, handling, storage	Contractor's files,	
Pre and post treatment observations	Contractor files	
Incident reports	Incident Management database and contractor's files	
Licenses and permits	Contractor's files, if required	
Meeting minutes - internal		
Meeting minutes – meetings with contractors (e.g. start-up, quarterly meetings)	Senior Maintenance Planner's files	
Road Use Agreements		
Safe Work Plans • Line Construction Manager • Inspection Contractors	• Maintenance Planning Coordinator's files • Maintenance Planning Coordinator's and contractor's files	
Town/City Agreements		
Inspection Contractor audit (by FortisBC)	Line Construction Manager files	
Inspection Contractor audit (in-house)	Inspection Contractor files	

11.0 Definitions

The following terms are commonly used in the context of wood pole structure maintenance:

Break:	Separation of wood fibres across the axis of a pole (not to be confused with a check).
Butt Treated:	The commercial treatment of the lower part of a pole, from the butt to about 2 feet (60 cm) above the normal ground line. Incising is often also part of the treatment.
Checks:	A V-shaped crack which separates the wood lengthwise along the wood fibres. Checks that extend to the centre of the pole are often caused as the pole dries and seasons. Checks do not reduce the strength of a pole but do serve as avenues for decay spores to enter the pole. Compression wood is the separation above ground of the sap wood from the heart wood Checks that run along bolts create an unsafe condition and shall be documented on the report form. Checks that do not run through an entire pole or along a bolt are common and do not create a pole hazard.
Cross Break:	Separation of wood fibres across the grain, usually caused by mechanical strain. Cracks seriously weaken poles. Not to be confused with a Check.
Creosote:	Certain distillates of tar suitable for wood preservation.
Decay (Biological):	Decomposition of wood substance by organisms such as wood destroying fungi.
Deep Decay:	Decomposition of wood substance by organism occurring below the normal test excavation depth. Internal decay, hollow heart
Defect:	A physical characteristic that reduces the strength of a pole (e.g., bird hole, rot, etc.).
Effective Groundline Circumference:	The measured circumference of a pole, in the ground line area, minus allowances for external decay defects that reduce the strength of the pole.
Exposed Pocket:	A bird hole or a pocket of decay in the side of a pole. May be associated with checks or external damage.
External Decay:	Surface rot, rot in exposed pockets, and insect infested sapwood.
Full Length Treatment:	The commercial treatment of an entire pole using either a Thermal or a Pressure Process.
Fumigant Treatment:	Application of chemical treatment into the pole to arrest and control internal decay or kill insects.
Fungus/Fungi:	Filamentous organisms that obtain their nutrition by degrading other materials, including wood.
Ground Line Section:	That part of a wood pole that is one foot above and two feet below the groundline.
Ground Line	Decay found near the ground line. Depending on soil conditions, decay may

Decay:	start at ground line and extend either up or down a pole.
Heart Rot:	Decay taking place inside the pole and working from the centre to the outside.
Heart Wood:	The inner part of a wood pole that, in the living tree, is no longer used to transport water and minerals from the roots to the leaves.
Hollow Heart:	Internal decay where the pole is hollow or the wood badly decomposed near the centre of the pole.
Mechanical Damage:	Often caused by vehicle / farm implements which results in unsymmetrical damage or cross breaks. A broken pole shall be recommended for replacement and reported immediately to the Line Construction Manager. No Treatment Zones
Pressure Process	A commercial Treatment where a liquid preservative is forced into a pole at a pressure above atmospheric.
Rejected:	A rejected pole is any pole, which upon inspection, is deteriorated below required strength.
Rot:	Decomposition of wood substance by wood destroying fungi.
Sapwood:	The outer part of a pole that, in the living tree, is used to transport water and minerals from the roots to the leaves.
Shell Rot:	Rotten Sapwood normally considered on the above ground part of a pole. When severe, shell rot seriously reduces the remaining pole strength.
Shell Thickness:	Radial thickness of sound wood surrounding internal decay.
Sound & Bore:	Poles designated by the Company and not subject for normal excavation inspection are to be sounded from below ground line to as high as a workman can reach above ground line and bored to locate interior decay.
Split:	Means a separation along the grain forming a check that extends through the pole from one surface to another. In other words, it is a through check.
Stub:	A steel beam or a section of wood pole material that is used to reinforce a pole below the ground line. A stub is 10 - 14 feet (3 - 4.25 m) in length and is inserted into the ground alongside a pole and fastened to it with steel bands or bolts.
Stubbed Pole:	A pole that is supported at ground line with a Stub.
Treated Pole:	A treated pole is any butt treated or full-length treated pole that is 15 years old, or older, and upon inspection, is found to be sound enough to warrant preservative treatment or reinforcement.
Treatment:	Application of a preservative to a pole.
Woodpecker Damage:	Generally, small woodpecker holes that are few and far between, particularly those that follow checks, do not significantly reduce the strength of a pole.

Appendix A – Approved Internal and External Treatment Products

Products must be listed in the current Wood Pole Pest Management Plan:

A.1 Approved Preservative Bandages

Preservative bandages approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- PoleWrap made by North Star Structural Contractors, Ltd.,
- CobraWrap made by Genics Inc.
- Cu-Bor made by Copper Care Wood Preservatives, Inc.

A.2 Approved Treatment Rods

Remedial treatment rods approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- CobraRod made by Genics Inc.,
- Flurods made by NorthStar Structural Contractors Ltd.,
- Impel rods made by Wood-Slimp GMBH

A.3 Approved Fumigants

Fumigants approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- Pole-Fume made by Amvac Chemical Corporation,
- Woodfume made by NorthStar Structural Contractors Ltd.,
- Guardsman Post & Pole Fumigant made by Univar Canada Ltd.,

A.4 Approved Cavity Floods

Cavity floods approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- Tim-bor made by U.S. Borax Inc.
- Boracol made by Wood-Slimp GMBH
- Copper Naphthenate
- GenBor RTU-2 made by Genics Inc.

A.5 Approved Insecticides

Insecticides registered by the PMRA for the effective control of carpenter ants can be used on FortisBC's Pole Testing and Re-Treatment program.

FortisBC

Transmission System Programs

Revision Date: May 25, 2011 | Rev. 0 | Document No.: 801-03

Appendix 2

Clearance Spreadsheet

Appendix 2 - Clearances Violation Spreadsheet

Date	Time (24Hr)	Clearance Violation Between		Elevation at Each Structure		Span Between Structures	Conductor Type	Weather Conditions	Ambient Temperature	Clearance Where Violation Occurs	PLT	Comments
		Structure #	Structure #									

Appendix H

Distribution Planning Manual

Distribution

Planning Manual

March 25, 2011

Table of Contents

1 Distribution Planning Philosophy

This document identifies the philosophy utilized by System Planning in the development of the distribution system with voltage levels 35 kV and below.

1.1 Goals

- To plan the development of the most economical distribution systems that will provide service within specified standards to meet projected distribution loads of the future.
- Determine the changes required over the next five years to maintain standards of service while at the same time providing the most economical development of future distribution systems.
- Evaluate new facilities or anticipated rebuilds by comparing alternatives and recommending changes that will produce the most economical long-term development of the future distribution system.

1.2 Activities

- Project growth rates and forecast future load for areas within the service boundaries. Communicate with Regional Districts, Town Planners, etc., to gather information on anticipated development plans in their respective areas to incorporate into load forecasts.
- Develop alternative plans for systems that will supply projected future loads. Analyze each plan. Select the most economical as the long-range plan. Revise the long range plans and five year plans as a result of changing load patterns, regional and municipal plans or changing service standards.

1.3 Standards of Service

- Maximum feeder load during normal operating conditions is limited to the ampacity of the underground cable or overhead conductor exiting the substation. Refer to section 2.2 “Overhead Conductor and Underground Cable Ampacity”
- Maximum distribution equipment load during normal operating conditions is limited to the continuous rating of the equipment unless otherwise specified. Refer to section 2.3 “Capacity of Distribution Equipment”.
- Minimum Voltage as per CSA publication C235 “preferred Voltage Levels for AC Systems, 0 to 50,000 Volts”. Refer to Section 2.1
- Maximum Voltage as per CSA publication C235 “preferred Voltage Levels for AC Systems, 0 to 50,000 Volts”. Refer to Section 2.1
- Maximum three phase fault current is 8000 amps on primary distribution systems.
- Maximum single line to ground fault current is 5000 amps on primary distribution systems.
- Maximum load/L-G short circuit ratio is 25%.
- Maximum load/3-P short circuit ratio is 40%.

2 Planning Criteria

2.1 Voltage - Steady State Criteria

2.1.1 Introduction

This Planning criterion covers the application of minimum and maximum voltage levels on the distribution system. This criterion specifies the minimum and maximum voltage levels under steady state conditions used to plan the distribution system.

2.1.2 Planning Criteria

Planning designs the distribution feeders to ensure that customers have acceptable voltage at their utilization point. Planning will take corrective action when the predicted loading on the distribution feeder model indicates that the primary voltage (three phase and/or single phase) is outside of the minimum or maximum voltage parameters stated below:

Table 1- Planning Voltage Criteria

(on a 120 Volt base)	Minimum	Maximum
Three Phase Voltage	115 V	127 V
Single Phase Voltage	113 V	127 V

The minimum voltages shown above apply when the source voltage is set at 123.5 V and the maximum voltages shown above apply when the source voltage is set at 126.5 V. The 123.5 V and 126.5 V levels reflect the typical operating range of a source substation.

2.1.3 Background

Planning assesses the need for voltage support to ensure that customers have acceptable voltage at their utilization point in accordance with CSA Standard CAN3-C235-83: “Preferred Voltage Levels for AC systems 1 to 50 000 V”. This standard outlines the recommended steady state voltage variation limits for circuits up to 1000 V at the utilization point (i.e. plug in) as follows:

Table 2 – CSA Preferred Voltage Levels

	NORMAL	EXTREME
Three Phase	110 V – 125 V	108 V – 127 V
Single Phase	108 V – 125 V	104 V – 127 V

Planning will initiate voltage improvements when the voltage reaches or is projected to reach the minimum recommended voltage under normal operating conditions. Corrective action is also initiated for instances where the voltage is or is expected to be in excess of the maximum recommended levels under normal operating conditions.

Some extreme operating conditions are temporary in nature. So the decision to initiate system improvements will depend on factors such as location, customer type and the extent to which limits are exceeded (i.e. magnitude and duration reflecting safety concerns as well as the probability of equipment damage).

2.1.4 Process

Recognizing that the specified CSA voltage limits apply at the utilization point, some allowance must be made for the voltage regulation through the service transformer as well as the secondary and internal wiring voltage drop to the plug ins. Generally, a 3-5 V drop from the main line to the customer utilization point under peak loading conditions and a 1–2 V drop under light load are assumed. In order to comply with CSA limits, planning models the distribution feeder and will take corrective action when the primary voltage of a peak load feeder model indicates an existing or projected steady state voltage of 115 V (120 V base) or less on the three phase lines and/or 113 V (120 V base) or less on single phase lines. Similarly, Planning will take corrective action when the primary voltage of a light load feeder model (three phase or single phase) indicates an existing or projected steady state voltage of 127 V (120 V base) or more.

2.2 Overhead Conductor and Underground Cable Ampacity

2.2.1 Introduction

This document covers the Planning Criteria for the application of ampacity levels for overhead conductors and underground cable used in the distribution system. This document specifies the maximum ampacity levels used to plan the distribution system.

During actual operations, higher ampacity ratings may be used taking into account actual temperatures, wind speed, pre-loading and duration of loading. Operation at higher ampacity levels may reduce the life of the equipment in order to supply load and such risks will be assessed at time of operation.

2.2.2 Planning Criteria

Planning designs the distribution feeders to ensure that the conductors, cables and connectors, on the distribution system, have the capability to supply customer load. The distribution feeder must be able to supply customer load for forecast load conditions without any conductor, cable and connector loss of life.

This document outlines the normal ampacity ratings for overhead conductors, underground cable, and the maximum feeder loading used by Planning in the distribution system.

2.2.3 Overhead Conductor

Planning models the distribution feeders to ensure that the overhead conductors are not loaded above their ampacity ratings. Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above its rating under the forecast peak load conditions.

Table 3 – Overhead Conductor Ampacity Limits

Summer Rating Table										
Conductor Type	Normal Rating					Emergency Rating				
		MVA by Voltage					MVA By Voltage			
	Ampacity (Amps)	$25kV_{LL}$ 3Ø	$14.4kV_{LG}$ 1Ø	$13kV_{LL}$ 3Ø	$7.2kV_{LG}$ 1Ø	Ampacity (Amps)	$25kV_{LL}$ 3Ø	$14.4kV_{LG}$ 1Ø	$13kV_{LL}$ 3Ø	$7.2kV_{LG}$ 1Ø
#8 Cu	92	4.0	2.3	2.1	1.2	102	4.4	2.5	2.3	1.3
#6 Cu	125	5.4	3.1	2.8	1.6	136	5.9	3.4	3.1	1.8
#4 Cu	164	7.1	4.1	3.7	2.1	182	7.9	4.6	4.1	2.4
#3 Cu	192	8.3	4.8	4.3	2.5	210	9.1	5.3	4.8	2.8
2ACSR	180	7.7	4.0	4.1	2.3	196	8.5	4.9	4.4	2.5
#2 Cu	222	9.6	5.5	5.0	2.9	245	10.6	6.1	5.5	3.2
2/0 ACSR	278	12.0	7.0	6.3	3.6	366	15.8	9.2	8.2	4.8
3/0 ACSR	321	13.9	8.0	7.2	4.2	425	18.4	10.6	9.6	5.5
90 KCMIL Cu	256	11.1	6.4	5.8	3.3	282	12.2	7.1	6.3	3.7
266 ACSR	429	18.6	10.7	9.7	5.6	572	24.8	14.3	12.9	7.4
336 ACSR	496	21.5	12.4	11.2	6.4	664	28.8	16.6	15.0	8.6
397 ACSR	550	23.8	13.8	12.4	7.2	739	32.0	18.5	16.6	9.6
477 ACSR	609	26.4	15.2	13.7	7.9	819	35.5	20.5	18.4	10.6
927 AAC	912	39.5	22.8	20.5	11.9	1022	44.3	25.6	23.0	13.3

Winter Rating Table										
Conductor Type	Normal Rating					Emergency Rating				
	Ampacity (Amps)	MVA by Voltage				Ampacity (Amps)	MVA By Voltage			
		$25kV_{LL}$ 3Ø	$14.4kV_{LG}$ 1Ø	$13kV_{LL}$ 3Ø	$7.2kV_{LG}$ 1Ø		$25kV_{LL}$ 3Ø	$14.4kV_{LG}$ 1Ø	$13kV_{LL}$ 3Ø	$7.2kV_{LG}$ 1Ø
#8 Cu	127	5.5	3.2	2.9	1.7	134	5.8	3.3	3.0	1.7
#6 Cu	171	7.4	4.3	3.8	2.2	178	7.7	4.4	4.0	2.3
#4 Cu	229	9.9	5.7	5.1	2.9	238	10.3	5.9	5.4	3.1
#3 Cu	264	11.4	6.6	5.9	3.4	276	11.9	6.9	6.2	3.6
2ACSR	248	10.7	6.2	5.6	3.2	285	12.3	7.1	6.4	3.7
#2 Cu	305	13.2	7.6	6.9	4.0	319	13.8	8.0	7.2	4.2
2/0 ACSR	385	16.7	9.6	8.7	5.0	444	19.2	11.1	10.0	5.8
3/0 ACSR	446	19.3	11.2	10.0	5.8	516	22.3	12.9	11.6	6.7
90 KCMIL Cu	353	15.3	8.8	7.9	4.6	370	16.0	9.3	8.3	4.8
266 ACSR	598	25.9	15.0	13.5	7.8	695	30.1	17.4	15.6	9.0
336 ACSR	693	30.0	17.3	15.6	9.0	806	34.9	20.2	18.1	10.5
397 ACSR	770	33.3	19.3	17.3	10.0	898	38.9	22.5	20.2	11.7
477 ACSR	854	37.0	21.4	19.2	11.1	995	43.1	24.9	22.4	12.9
927 AAC	1288	55.8	32.2	29.0	16.7	1357	58.8	33.9	30.6	17.6

2.2.4 Underground Cable

Planning models the distribution feeders to ensure that the underground cables are not loaded above their ampacity ratings. Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above their rating under the forecast peak load conditions.

Refer to Drawing Standard 1301 “15 kV and 25 kV Underground and Riser Cable Ampacities” from Distribution Standards for latest version located on G:\Standards\Distribution\Current Distribution Structures Manual and FortisBC Underground Design Criteria (in development stage) for the rating ampacities of underground cables (current document is attached for reference).

2.3 Capacity of Distribution Equipment

2.3.1 Introduction

This document covers Planning Criteria for the application of ampacity levels for equipment used on the distribution system. This document specifies the maximum ampacity levels used to plan the distribution system.

Under actual operations, higher ampacity ratings may be used taking into account actual temperatures, wind speed, pre-loading and duration of loading. Operation at higher ampacity levels may reduce the life of the equipment in order to supply load and such risks will be assessed at time of operation.

2.3.2 Planning Criteria

Planning designs the distribution feeders to ensure that the equipment on the distribution system has the capability to supply customer load for forecast load conditions. This Planning criterion outlines the ampacity ratings for equipment used in the distribution system.

2.3.3 Distribution Service Transformers, Voltage Regulators and Switches

Planning models the distribution feeders to ensure that the distribution line voltage regulators and switching devices are not loaded above their ratings.

Planning does not model individual service transformer loading, but recommends that when load is found to exceed the rating on these transformers that corrective action is taken.

Planning will take corrective action, when the model of the distribution feeder indicates that any equipment will be operated above the rating of the equipment under the forecast peak load conditions.

Table 2.3.3 – Distribution Equipment Capacity

Voltage Regulators	100% of Nameplate Rating
Switches and Cutouts	100% of Continuous Rating
Distribution Service Transformers	100% of Nameplate Rating

2.3.4 Distribution Source Transformers

Planning monitors the load on distribution source transformers to ensure that they are not loaded above their ratings.

Distribution source transformers are those that supply distribution feeders at 25 kV or below, predominantly 25 kV and 13 kV, including transmission transformer tertiary windings where used.

Transformer capacity upgrades will be planned in the year that the forecast transformer load:

(1) exceeds nameplate rating at the forecast summer peak, or
(2) exceeds nameplate rating plus 25% at the forecast winter peak.

3 Contingency Planning Guidelines

3.1 Introduction

This guideline addresses the criteria for backup associated with the distribution system. Backup in addition to service continuity (i.e., absence of interruptions) composes reliability. Backup refers to the ability to restore service after an interruption without necessarily first repairing the cause of the interruption.

3.2 Contingency Requirements

3.2.1 Distribution Feeder Contingencies

Planning will assess the distribution system to determine the backup capability for a single Distribution contingency event. In the event of a single Distribution contingency, a percentage of the peak load must be able to be supplied from the remaining distribution feeders in the study area. The percentage of peak load to be supplied is determined from the load duration curve shown below if available or 80% of peak load.

After the interruption, without first repairing the cause of the interruption, the remaining distribution feeders should have the capability to supply the load on the upper flat portion of the load duration curve. In the graph below, this would be 7 MW. Hence, it is recognized, that during peak load conditions the remaining distribution system may not have the capability to supply the entire load in the event of a distribution contingency.

In municipalities that require subdivisions be supplied underground, the company will ensure that all new underground circuits are looped and that the load can be fully supplied by either end of the loop for a single cable section failure.

When determining the capability of the remaining distribution system in the event of a distribution contingency, the minimum voltage level will be allowed to drop by 2 V to 113 V for three phase and 111 V for single phase.

Planning will take corrective action, when for the predicted loading, the distribution system is not capable of meeting this backup criteria.

3.2.2 Distribution Transformer Contingencies

Planning will study the distribution system to develop the backup requirement for the loss of one substation transformer in either a single or multi transformer substation.

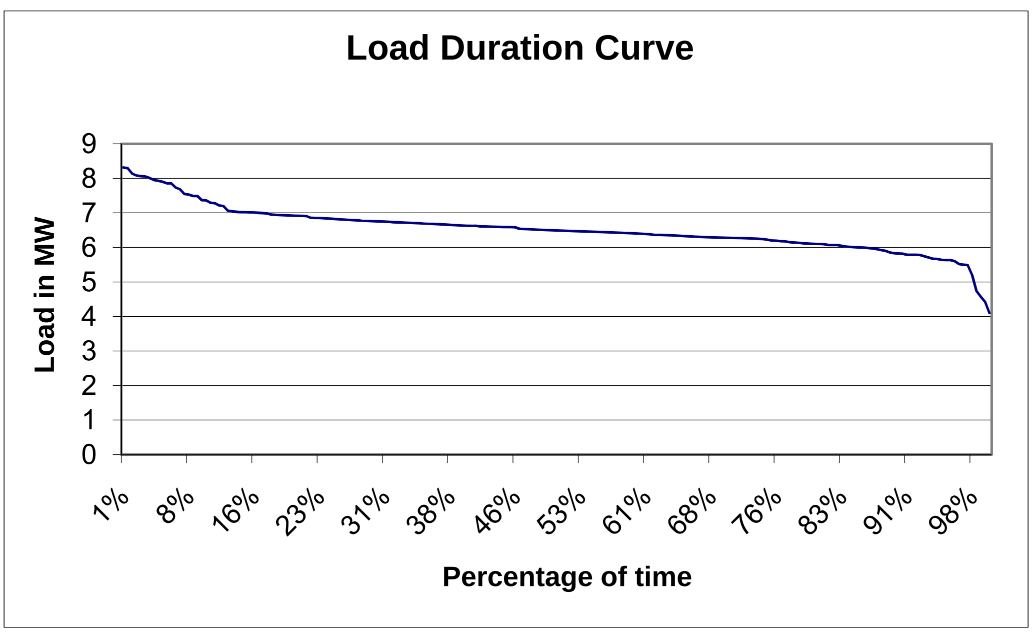
- For loss of the transformer in a single transformer substation, a percentage of the peak load normally supplied by that transformer must be able to be supplied from the remaining distribution feeders and substations in the study area. The percentage of peak load to be supplied is determined from the load duration curve shown below if available or 80% of peak load. After the interruption, without first repairing the cause of the interruption, the remaining distribution feeders should have the capability to supply the load on the upper flat portion of the load duration curve. In the graph below, this would be 7 MW. Hence, it is recognized, that during peak load conditions the distribution system may not have the capability to supply the entire load in the event of the loss of the single transformer and full recovery may be dependent on installation of a mobile transformer.

- For loss of a single transformer in a multi transformer substation, 100 percent of the peak load must be able to be supplied from the remaining station transformer or a combination of the remaining station transformer and other supplies in the study area.

When determining the capability of the distribution system, in the event of the loss of the single transformer, the minimum voltage level will be allowed to drop by 2 V to 113 V for three phase and 111 V for single phase.

Planning will take corrective action, when for the predicted loading, the distribution system is not capable of meeting this backup criteria.

Graph 3.2.2 – Typical Load Duration Curve



4 25 kV Conversion Planning Criteria

4.1 Problem

As loads continually grow and expand in a distribution network they utilize the system voltage available in the area. Overtime the loads may eventually reach a point where it makes better business and operational sense to convert the distribution source voltage to a higher level. The unfortunate part is that the loads were all installed using a certain voltage level and to increase the voltage requires all the insulation/service transformers and potential underground cables on the distribution system to be upgraded.

4.2 Purpose

This document outlines the benefits of using a higher voltage and when to consider converting a distribution system or section of a distribution system to a higher voltage. The document discusses 12.47kV to 25kV conversions as they are the most common.

4.3 Discussion

Higher distribution voltages create less losses and in turn less voltage drop and therefore can be used to supply customers over a longer distance. Typically utilities upgrade 4 and 8 kV systems to 12.47 kV and then to 25 kV. The following paragraphs outline some of the advantages/criteria used to justify a conversion to a higher voltage.

4.3.1 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 divide the line current by half. 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%. For example an existing 12.47 kV feeder supplies a feeder with a demand of 1MVA. The line current is approximately 46A and the losses in the line are, using 100Ω, 211.6 kW. Using 25kV with the same conductor (100Ω) and load (1 MVA) the line current is 23A and the losses are 53.5 kW. Therefore by increasing the voltage by 100% the losses are reduced by 75%.

4.3.2 Distance

Because the losses are so much less in a 25 kV system, as outlined above, the voltage drop along the distribution line is less than that of a 12.47 kV system and the feeder can therefore extend out into the service territory much farther than

12.47 kV. This makes 25 kV an excellent voltage to use on rural feeders as the substation can still be placed in or near the load centre and be able to reach out into the suburbs or outlying areas.

4.3.3 Operational

Work procedures are very similar for 4 kV and 25 kV systems, with the exception of limits of approach. Working on voltages above 25 kV cannot be done using FortisBC distribution hot work procedures and transmission procedures would have to be followed which essentially means all the hot would have to be performed using sticking techniques.

Historically stations in the FortisBC service territory were supplied at 63 kV and spread out every 30-50 km (Approximate) with a 12.47 distribution voltage to serve customers. When these stations hit the planning criteria required to upgrade them from a capacity perspective the neighboring stations should be investigated to determine if a new 25 kV station placed in a strategic location, could offload the already overloaded station and the neighboring stations. The initial cost of the upgrade is higher than a like for like replacement at the same voltage, but the long term payback is probably better if, for example, converting to 25 kV in one station eliminates the need for multiple neighboring stations.

Dense urban locations/load canters do not require the long reach benefit from the 25 kV source as all the load is utilized before the feeder impedance can cause any problems from an undervoltage perspective. The losses are still much higher on these lines, but the payback to convert urban areas to 25 kV is rarely justifiable.

Consideration should be given to install step up banks from 12.47 kV distribution lines to 25 kV distribution lines if there are very few long distribution lines from the station. In these cases converting the entire distribution system to 25 kV would not be a cost effective solution as the only part of the feeder requiring 25 kV is a small portion and a small step up bank can be installed to accommodate this or a regulator.

FORTISBC UNDERGROUND AND RISER CABLES AMPACITIES

STUDY NUMBER	CABLE SIZE	VOLTAGE kV PHASE-TO-PHASE	FBC MATERIAL ITEM NUMBER	GROUNDING (NEUTRAL CONDUCTOR)	DUCT SIZE & TYPE	PHASES	CONDUCTOR PER PHASE	CONFIGURATION	NUMBER OF DUCTS	BURIED IN DUCT LOAD FACTOR vs TEMP (°C): LF = 1 90°C 20°C EARTH AMBIENT	LF = 1 110°C 20°C EARTH AMBIENT	LF = 1 130°C 20°C EARTH AMBIENT	LF = 0.8 90°C 20°C EARTH AMBIENT	LF = 0.8 110°C 20°C EARTH AMBIENT	LF = 0.8 130°C 20°C EARTH AMBIENT	LF = 0.6 90°C 20°C EARTH AMBIENT	LF = 0.6 110°C 20°C EARTH AMBIENT	LF = 0.6 130°C 20°C EARTH AMBIENT	CABLE AT RISER LOAD FACTOR vs TEMP (°C): LF = 1 90°C 40°C AIR AMBIENT	LF = 1 110°C 40°C AIR AMBIENT	LF = 1 130°C 40°C AIR AMBIENT
1	#2 Cu	15	534-3103	BOTH ENDS	3" PVC FOR UG & RISER	1	1	1 CABLE 1 DUCT	1	166	186	203	171	191	208	175	195	213	136	162	184
2	#2 Cu	15	534-3103	BOTH ENDS	4" PVC FOR UG & RISER	3	1	3 CABLE 1 DUCT	1	165	185	201	173	193	210	179	200	218	147	175	199
3	#1 Cu	25	534-4102	BOTH ENDS	3" PVC FOR UG & RISER	1	1	1 CABLE 1 DUCT	1	190	212	231	195	218	238	200	223	244	155	186	211
4	#1 Cu	25	534-4102	BOTH ENDS	4" PVC FOR UG & RISER	3	1	3 CABLE 1 DUCT	1	186	208	226	195	217	236	202	226	245	167	199	225
5	#1 Al	25	534-4103	BOTH ENDS	3" PVC FOR UG & RISER	1	1	1 CABLE 1 DUCT	1	149	167	181	153	171	187	157	175	191	122	146	166
6	#1 Al	25	534-4103	BOTH ENDS	4" PVC FOR UG & RISER	3	1	3 CABLE 1 DUCT	1	144	161	175	151	168	183	157	175	190	130	154	174
7	350 Al	15	534-3104	BOTH ENDS	3" PVC FOR UG & RISER	3	1	1 CABLE 1 DUCT	3	334	376	412	356	401	440	378	426	468	323	390	446
8	350 Al	15	534-3104	BOTH ENDS	4" PVC FOR UG & RISER	3	1	3 CABLE 1 DUCT	1	322	359	391	339	379	413	355	397	433	298	356	404
9	500 Al	25	534-4109	BOTH ENDS	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	389	439	483	418	473	520	447	506	557	405	490	562
10	500 Al	25	534-4109	ONE END	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	473	526	570	506	563	611	538	599	651	467	556	629
11	750 Al	15	534-3105	BOTH ENDS	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	428	485	536	463	526	582	499	567	628	460	562	650
12	750 Al	15	534-3105	ONE END	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	589	655	711	633	705	766	677	755	821	592	707	803
13	750 Al	25	534-4111	BOTH ENDS	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	437	494	545	474	537	592	512	580	640	468	568	654
14	750 Al	25	534-4111	ONE END	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	590	655	709	635	705	764	679	755	819	588	700	791
15	1000 Al	15	534-3107	BOTH ENDS	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	470	533	589	511	581	643	554	630	698	517	631	732
16	1000 Al	15	534-3107	ONE END	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	706	785	852	762	849	923	820	914	995	722	862	979
17	1000 Cu	25	534-4108	BOTH ENDS	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	529	597	656	576	651	717	625	707	780	583	710	821
18	1000 Cu	25	534-4108	ONE END	4" PVC FOR UG PE FOR RISER	3	1	1 CABLE 1 DUCT	3	879	977	1060	947	1054	1144	1015	1131	1229	894	1065	1207

NOTES:

1) THIS TABLE WAS CREATED WITH CYMCAP SOFTWARE WITH THE FOLLOWING ASSUMPTIONS:

1.1) ASSUMPTIONS FOR UG INSTALLATION:

- CABLES ARE BURIED IN PVC DUCTS IN 1000mm (≈40") DEPTH FROM GRADE LEVEL WITH 190mm (≈7.5") SPACING BETWEEN CENTRE-TO-CENTRE OF DUCTS.
- EARTH AMBIENT TEMPERATURE: 20°C
- LOAD FACTORS: LF=1, LF=0.8, & LF=0.6
- THERMAL CONDUCTIVITY OF BACKFILL SOIL: 0.7 °C.m/W
- BACKFILL IS COMMON SAND WITH 5% MOISTURE CONTENT

1.1) ASSUMPTIONS FOR RISER APPLICATION:

- NO WIND, FULL SUN, VENTED AT TOP OF DUCTS
- USE PVC DUCTS FOR CABLES LESS THAN 500MCM. USE PE DUCTS FOR CABLES 500MCM AND ABOVE.
- INTENSITY OF SOLAR RADIATION: 925.013 W/m^2
- AIR AMBIENT TEMPERATURE: 40°C
- LOAD FACTORS: LF=1
- SPACE BETWEEN DUCTS 127mm (≈5") CENTRE-TO-CENTRE
- RISER LENGTH: 9.14m (30')

2) CURRENT RATINGS ARE PER CONDUCTOR AS STEADY BASE.

3) WHERE BONDING IS AT ONE END ONLY, A SEPARATE NEUTRAL CONDUCTOR IS USED FOR RETURN PATH.

4) THE LOAD FACTOR IS THE RATIO OF THE AVERAGE LOAD OVER A DESIGNATED PERIOD OF TIME TO THE PEAK LOAD OCCURRING IN THAT PERIOD. FOR VARIABLE CONTINUOUS LOADING, THE BASE PERIOD IS 24 HOURS.

5) OPERATION AT THE EMERGENCY OVERLOAD TEMPERATURE OF 130°C SHALL NOT EXCEED 100 HOURS IN ANY 12 CONSECUTIVE MONTHS NOR MORE THAN 500 HOURS DURING THE LIFETIME OF THE CABLE.

6) LOAD FACTOR FOR RISER APPLICATIONS IS CONSIDERED 1.0 FOR ALL SCENARIOS AS THE CABLES IN AIR RAPIDLY REACH STEADY STATE DUE TO LOW THERMAL TIME CONSTANT OF AIR.

7) THE TABLE REPRESENTS CABLE AMPACITY ONLY, NOT FEEDER AMPACITY. REFER TO FORTISBC DISTRIBUTION DESIGN CRITERIA FOR FEEDER AMPACITY CRITERIA.

8) CABLES BURIED IN DUCT VALUES CALCULATED WITH CYMCAP V5.0 R3
CABLE RISER VALUES CALCULATED WITH CYMCAP V5.3 R1, DUE TO ERROR IN V5.0 R3 FOR RISER APPLICATIONS.

PROFESSIONAL ENGINEER
PROVINCE OF BRITISH COLUMBIA
S. AHMAD
34552

01 June, 2011

REV	DATE	BY	CHECKED	DESCRIPTION	APP.	DATE
6						
5						
4						
3						
2						
1	MAY/11	ST	ST	REVISED ALL CABLE RISER VALUES. REPLACED CABLE 534-3106 WITH 534-4108. ADDED NOTE 8	SA	MAY/11

DRAWN BY	LDR	AUG/10
CHECKED BY	ST	OCT/10
APPROVED BY	SA	OCT/10

15kV & 25kV UNDERGROUND AND RISER CABLES AMPACITIES

FORTISBC

DRAWING No.	REV.
[illegible]	1

Appendix I

Distribution System Programs

FortisBC
Distribution System Programs
Document 801-02

Date	Rev	Description	Author	Approved
03/29/2011	0	Distribution overhead and underground system programs	DK, BM, DM	GW, MA

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Distribution System Programs

Revision Date: March 29, 2011 Rev. 0 Document No.: 801-02

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Distribution System Programs

Revision Date: March 29, 2011 Rev. 0 Document No.: 801-02

1. Introduction

The Distribution System Programs involve an evaluation of the integrity of its physical characteristics and conformance to appropriate regulations. Patrols and assessments are conducted to identify deficiencies in the electrical system owned or maintained by FortisBC that could compromise safety, service reliability, or line integrity.

1.1 Scope

This document outlines requirements and guidelines for the Distribution System programs of all types owned and/or operated by FortisBC.

The distribution system is comprised of all overhead and underground Company-owned or maintained primary and secondary components beginning at point-of-delivery of the system through to the customer meters or termination points.

This document provides general information about the Distribution System Programs. Experience and judgement of the patroller is critical for assessing deficiencies and determining the appropriate response for repair.

1.2 Using This Document

It is the responsibility of persons using this document to seek clarification, where needed, from the Distribution Planner.

1.3 Competency of Patrollers

The minimum competency required to patrol the electrical distribution system is that of a “qualified employee” (see definitions).

1.4 As-Built Process

The As-built process is very critical to the integrity of data going forward. It is very important that the As-built process is followed when anything is changed in the system whether it is a result of an Urgent Repair, Annual Line Patrol or Rehabilitation. It is not within the scope of this document to outline the As-built process.

2. Benefits of Distribution System Programs

FortisBC conducts a series of patrols and inspections of all distribution system facilities that it owns or operates. These predictive maintenance programs provide information in the form of data, statistics, observations, assessments, and recommendations of corrective action to be performed on the distribution system to ensure public and employee safety, provides appropriate reliability, and prevents high consequence failures.

The information collected from the patrols/assessments is combined with information concerning reliability, consequence of failure, (to customer and FortisBC), public safety concerns, and the environment

3. Roles and Responsibilities

3.1 Planning

Planning will determine the eight-year cycle for the Condition Assessment program and will also be responsible for the prioritization and modifications to the schedule, if necessary, over the course of the cycle. The schedule and any modifications to the schedule have to be reported to the Arc FM (GIS) group by planning. Planning will work with Project Management to estimate costs for the Condition Assessment and Rehabilitation programs every capital cycle for submission to the BC Utilities Commission. This document is owned by Planning and therefore Planning is responsible for any changes or modifications.

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3.2 Engineering

Engineering will be responsible for compiling the Condition Assessment reports and reviewing with Operations and Planning. Engineering will also be responsible for preparing the rehabilitation packages that result from the Condition Assessments.

The Arc FM (GIS) group will be responsible for creating all map books for the Test and Treat and Condition Assessment assessors for the appropriate project area boundaries. Once the data is entered into ArcFM (GIS) by the field personnel, the ArcFM (GIS) group will also QA the integrity of the data. The ArcFM (GIS) group will also QA all As-built information once Rehabilitation is complete and entered into the Arc FM (GIS) system.

3.3 Project Management

Project Management will be responsible for the execution of the Condition Assessment and Rehabilitation programs. They will also be responsible for managing scheduling, budget, resourcing, ArcFM (GIS) data entry, and ensure a proper summary report get created for the Condition Assessment program. Project Management will also be required to work with Planning to communicate per unit costing of the Condition Assessment program to the Planning department to aid the estimating process for the Capital submissions for funding of these programs.

3.4 Network Services/Contractors

Network Services/Contractors will be responsible to perform the Annual Line Patrols and the Condition Assessment program on the eight-year cycle as dictated by Planning. They will ensure that all deficiencies identified from the patrols get corrected on an annual basis. Network Services/Contractors will also carry out the Rehabilitation work identified from the Condition Assessment program every eight years and provide the proper As-built data to the ArcFM (GIS) group when rehabilitation work is complete.

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Once Rehabilitation, for either Condition Assessment or the Annual Line Patrol, is complete on the feeder, then the Distribution As-built group will also be responsible for entering the As-built information in the ArcFM (GIS) system.

4. Types and Frequency of Patrols

FortisBC has three main types of Distribution System Programs:

1. Annual Line Patrol – Operations and Maintenance
2. Condition Assessment Program - Capital

4.1 Annual Line Patrol (ALP)

The ALP is an annual inspection done on all distribution plant as part of the region's Operations and Maintenance (O&M) budget. The regions consist of the North Okanagan, South Okanagan, Kootenay and Boundary. The ALP is a documented patrol by a competent qualified utility employee who successfully completes the internal training, to address imminent safety, environmental or system integrity concerns. Network Services determines the type of visual patrol using criteria such as safety, accessibility, reliability, known defects, outage statistics and system performance.

Foremen are accountable to ensure the ALPs are completed within their respective areas. Power Line Technician's perform the ALP as part of their day-to-day work, and report the line patrolled in the ArcFM (GIS) system including who did the patrol and the date of patrol.

Patrollers arrange with Dispatch to complete all high priority action items identified during the patrol. Anything that is identified that has failed already gets replaced under a Distribution Urgent Repair order, which is capitalized. All the other minor deficiencies get repaired under an operating repair order. Slightly larger deficiencies that are deemed by the patroller to be unable to make it to the next Condition Assessment cycle are to be noted in ArcFM (GIS) and submitted to the Regional Engineer for approval to be repaired under the Small Planned Capital budget. It is not the intent that the ArcFM (GIS) system will not be responsible for generating a list of all small planned capital projects that were submitted. It will however be capable of tracking the deficiency to ensure the information does not get lost.

Network Services will review the progress of the patrols to ensure all facilities are inspected annually.

4.2 Condition Assessment

The Distribution Condition Assessment program is the Company's capital sustaining program. The program is based on an eight-year cycle of condition assessing and testing and treating all of FortisBC's distribution line facilities and the schedule is determined by distribution planning.

The Test and Treat program involves drilling test holes in each pole to confirm the condition of the pole and addition of a pole treatment to reduce internal rot in the pole. The program extends the life of the pole and ensures the integrity of the lines as well as employee and public safety. The Test and Treat program is aimed at the section of pole at the ground level and below.

The Condition Assessment is aimed at the portion of the pole above the ground line which inspects things like the pole top condition, anchoring, crossarms, and insulators. If anything fails its inspection during the Condition Assessment or Test and Treat then the deficiency is documented and included in a rehabilitation package. The Condition Assessment data will determine the scope of work for the Distribution Rehabilitation program for the following year.

The Condition Assessment program is a documented assessment of the distribution system facilities by a competent qualified utility employee who successfully completes the internal training. Assessments require a thorough inspection of both overhead and underground equipment to look for potential safety hazards to employees or the public, and risks to system integrity.

Power Line Technicians, with the help of a Designer (if required) complete the Condition Assessment and report deficiencies electronically consistent with the guidelines outlined in sections 6 and 7 of this document. The Designer will then complete a rehabilitation package to be given back to the Project Manager to be scheduled into the following year's Rehabilitation program.

5. Annual Line Patrol Program Guidelines

The Annual Line Patrols consist of a drive by high level inspection of all the distribution plant every year. They are intended to identify failed and/or deficient equipment that occurred due to reasons beyond FortisBC control. These deficiencies are typically caused by vandalism, motor vehicle accidents, severe weather, etc. The patrols also identify unusual or new situations which may reduce line clearances, such as abnormally high water in boat or ferry areas, unusual/unfamiliar structures, signs of recent landscaping, changes in grade due to road or railway construction or maintenance, dirt or gravel heaps, buildings, grain bins, straw/hay stacks, etc.

On power line rights-of-way, items that require immediate attention include danger trees, gas storage facilities, and construction under power lines.

Power lines in the vicinity of airstrips and valley/water crossings must have marker balls installed. Unmarked or improperly marked power lines in the vicinity of airstrips and valley/water crossings must be assigned a high priority and corrected.

Stubs or poles left in ditches beyond the short window allowed during construction must be removed; this work will be dispatched through a capital salvage number.

Any energized or energizable points (i.e. equipment / conductors / terminals, etc.), or their enclosures, that are unlocked, damaged, open to reasonable public access, or otherwise unsafe, must be assigned a high priority and corrected immediately.

To ensure that two patrollers do not do a drive-by patrol on the same section of line, it is up to the Network Services group to track and manage the execution of the Annual Line Patrols. Deficiencies observed during the patrol are going to be tracked and corrected using the Dispatch tool.

5.1 Deficiency Rehabilitation Budgets

The following is FortisBC criteria to determine if a project should be charged to capital or O&M.

Capital Expenditures are expenditures in excess of $1,000 and that meet **all** of the following criteria:

1. Provide substantial benefits for a period of more than one year.
2. Extend the useful life of an asset or increase the capacity of an asset or increase the output efficiency or reduce operating costs (non-recurring expenditures).
3. Are held for use to conduct business/generate income.

It should be noted that the $1,000 has to absorb the following costs;

- Labour
- Contract work
- Vehicle hours
- Materials and supplies
- Overhead

The following summarizes what deficiencies should be applied to which budgets.

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Routine Maintenance Budget (Operating) – Any deficiencies severe enough to be unable to make it to the next Condition Assessment cycle (8 year maximum) and requires less than a $1,000 in value to repair.

Urgent Repair Budget (Capital) – Any deficiency involving failed equipment or equipment showing eminent signs of failure and requires more than $1,000 in value to repair.

Small Planned Capital Budget (Capital) – Any deficiencies that are severe enough to be unable to make it to the next Condition Assessment cycle (8 year maximum) and require more than a $1,000 in value to repair must be submitted to the Regional Engineers for approval and to the Arc FM (GIS) group for tracking purposes.

5.2 Criteria for Annual Line Patrol

Examples of the deficiencies to be assessed during the annual line patrol are as follows:

Capital deficiencies:

- ❑ Equipment causing an immediate hazard to the public with high potential for failure
- ❑ Severely rotted/cracked poles/crossarms
- ❑ Salvageable equipment
- ❑ Low primary line clearance
- ❑ Broken/damaged guy wires (consideration should be given as to whether the guy can be removed rather than repaired, e.g. farm service with slack span to transformer pole.)
- ❑ Missing/broken ground wire. Report all copper theft to the FortisBC standards department (diststan@fortisbc.com).
- ❑ Replace any oil filled equipment that is leaking onto the ground

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- ❑ Physical damage;
- ❑ Chipped broken insulators
- ❑ Blown/broken arrestor
- ❑ Install guy strain insulators
- ❑ Straighten severe leaning poles in locations that are highly visible to public and could be a hazard due to the amount of lean.

O&M deficiencies:

- ❑ Missing/broken guy guards
- ❑ Loose hot line clamps
- ❑ Missing or badly faded switch number tags
- ❑ Low secondary clearances (pull up triplex)
- ❑ Loose or missing hardware or connections;
- ❑ Equipment that is not secure
- ❑ Missing signs/tags
- ❑ Security locks and bolts that are not in place.
- ❑ Bird trap (bird traps that are obviously creating outages) – See Section 7 - Vegetation and Osprey Notification
- ❑ Report primary dips that look like they were installed illegally. This could be a potential power theft situation. If such a situation exists or is suspected to exist, please inform the operations foreman and the Manager of Revenue Protection.

Equipment checks are performed during ALPs as part of Network Service's predictive maintenance program. The foreman should decide which of the three budgets (O&M,

Urgent Repairs, and Small Planned Capital) should be applied to the correction of the deficiency and get an order number opened and dispatch started.

5.3 Safety Hazards Encountered During Patrols

Hazards encountered that pose a danger shall be handled as follows:

Immediate Danger

Safety hazards that could pose an immediate danger require the patroller to remain on site and secure the area affected by the danger.

The patroller shall take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If assistance is required, the patroller shall remain on site until qualified assistance or relief arrives.

No Immediate Danger

Safety hazards encountered that do not pose an immediate danger require the patroller to document the hazard and take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

5.4 Access Restrictions to Facilities

If access is restricted or the patroller is prevented from accessing, inspecting or maintaining facilities due to development (e.g. construction of a fence, building or driveway; planting of trees) report the condition to Operations Foreman to advise the customer.

Note any problems regarding vegetation to the Right of Way Supervisor (e.g. vegetation prohibiting access, insufficient clear distance for operating). Clear away any vegetation that is easily removed. See section 7 for more information.

6. Condition Assessment Program Guidelines

The Condition Assessment guidelines are broken out into each individual component throughout the following sections in detail. There are some guidelines described as to what is an urgent priority to be done right away under the Urgent Repair budget and what is Rehabilitation to be completed the following year.

6.1 Pole and Crossarm

Refer to Appendix 1, M10-04 FBC In-Service Wood Pole Inspection and Re-Treatment for information on above ground and below ground inspections of wood poles and the criteria for stubbing or replacement.

All results from the wood pole inspections and treatment needs to be entered into Arc FM (GIS) to flag red and blue tagged structures to ensure the Condition Assessment personal address the issues.

For cross arms requiring replacement, note the type of arm required and other material required because the FortisBC standard cross arm will not cover all applications.

Note: If a pole fails its inspection and will be getting replaced then it is very important to ensure that all joint use attachments are noted on the pole such as Shaw, Telus or any streetlight attachments. This will help ensure that when the new pole is installed and the old pole is salvaged that all the joint use attachments are properly As-built and recorded in ArcFM (GIS) for the new pole.

6.2 Insulation

If insulation is inadequate or in poor condition (cracks, chipped, etc) then new insulation should be recommended.

6.3 Lightning Arresters

Identify porcelain lightning arresters located in areas that present a high degree of risk to the general public. High-risk locations include schools, urban areas, commercial sites, recreation areas, subdivisions, and other areas with a high concentration of people). Porcelain arrestors in other areas, such as farms, oilfields and other rural areas pose a lower risk and should not be reported in unless the patroller assesses the location as a higher risk area.

6.4 Conductor Ties

Rust on an insulator may be an indicator of a broken or worn preformed tie and possible damage to the conductor and/or insulator. Closer visual may be required to see if the insert is missing or confirm if tie is broken or wearing.

A broken or rusted conductor tie may be an indication of other problems (e.g. sag too tight, damaged conductor).

6.5 Grounding

Ensure grounds are not missing, broken or excessively corroded. The case ground is attached on transformers; ensure ground wire is not broken or disconnected.

A three-phase transformer bank cannot be used to serve mixed services of delta and grounded-wye connections i.e. crowsfoot - report these locations in Arc FM (GIS) as they are a safety concern.

Check and repair connection between ground rod, connector and ground wire. Ground rods must be installed at every transformer/equipment pole and/or every third pole with no equipment attached.

6.6 Guys

Prior to doing repairs on or around a guy wire, complete a thorough inspection to identify hazards that could result in mechanical failure or electrical shock. Assess the risk that a guy assembly has on the public and employees. Line clearance, pole lean or damage, or other hazards associated with broken guys or pulled anchors must be considered and noted in Arc FM (GIS).

Add a guy strain insulator to a guy wire if the attachment point of an un-insulated guy wire on a non-metallic pole or structure is located above energized primary components. Johnny balls are not standard equipment at FortisBC but they will not be to be replaced as part of the Condition Assessment program unless they are damaged.

The eye of the guy rod should be exposed above grade if it is not add a guy extender of sufficient length to expose the eye.

Guy guards are to be installed during the annual line patrol and corrected but if missing/damaged guy guards are identified then they should be noted and installed/replaced. If multiple guys go to one anchor then guy guards only need to be installed on the outer two guys.

6.7 Conductor

Conductors that need to be re-tied or re-sagged should be noted and corrected.

Bird nesting, broken strands or pitting on conductor or problems with sleeves, noting phase(s) and location of the problem spots must be reported.

Be aware of other conductor conditions that could compromise safety or affect line integrity (e.g. circuits constructed under or crossing under other circuits where both circuits are not supported on the same structure).

6.8 Clearance

Be alert for unusual or new situations which may reduce line clearances, such as abnormally high water in boat or ferry areas, unusual/unfamiliar structures, signs of recent landscaping, changes in grade due to road or railway construction or maintenance, dirt or gravel heaps, buildings, straw/hay stacks, etc.

In order to ensure accurate measurements all clearance issues must be recorded electronically to capture the information outlined in Appendix 2.

For observations of dangerous customer-owned line clearances/equipment (e.g. over or near fuel tanks); inform the customer, report the deficiency to the foreman and jointly with the foreman determine if the deficiency is severe enough to report to the BC Safety Authority (1-866-566-7233).

6.9 Transformers and Switches

Only transformers that are leaking (dripping or have dripped) oil will be replaced if they cannot be easily repaired onsite. Sweating transformers located in riparian areas will be replaced.

All switches that require repairs to make them operable are to be tagged in the field with a Special Instruction Tag and will be a high priority to be fixed (Not included in the rehabilitation package). In-operable switches will be reported to the System Control Centre (SCC) (1-250-368-0542). When the switch has been repaired, the crew leader must remove the tag, and report back to SCC that the switch has been repaired. The only switch deficiencies that will be left for the rehabilitation project to remedy are those that do not deem the switch inoperable.

Missing or incorrect switch numbers fuse sizes, and normally open tags must be recorded in ArcFM (GIS) as a deficiency.

6.10 Padmount Transformers and Switching Cubicles

The following checks should be made at pad mount transformers and switching cubicles.

- Cabinet:
  - Rust – rusting through; superficial - Rehabilitation
  - Dented – causing encroachment to limits of approach – Urgent
  - Door or lid problems – bonding strap not connected; binding; hinge problems; missing stops – Rehabilitation
  - Oil leaks - Heavy - Urgent
    - Light - Rehabilitation
- Insulating caps:
  - Cap not sealed – Note if the insulating caps are not fully seated on the bushings. An attempt should be to seat cap back onto the bushing with a hot stick. If the cap will not seat properly, then it should be recorded - Urgent
  - Bleed wire – broken; missing; improperly connected – Rehabilitation
  - Tracking – any evidence - Urgent
  - Disfigured or rubber breakdown - Rehabilitation
- Primary Splices, Elbows, Stress Cones:
  - Overheating
    - Melting - Urgent
    - Disfigured or rubber breaking down - Rehabilitation
  - Bleed wire - broken; missing; improperly connected - Rehabilitation
  - Dirty – tracking/buzzing - Urgent
  - Discoloration or sealant leaking - Rehabilitation

- Neutral:
    - o Corrosion
        - Separated - Urgent
        - Pitting - Rehabilitation
    - o Aluminum or copper connections corroding:
        - Separated - Urgent
        - White powder - Rehabilitation
        - Minor amounts - Rehabilitation
    - o Ground grid (counterpoise) not in place
        - School, playground, residential area - Rehabilitation
        - Commercial - Rehabilitation
- Oil:
    - o Low or no oil - Urgent
- Tags and Equipment Identifiers:
    - o Any missing decals should be reported to SCC and replaced on the spot at the direction of SCC.
- Locks and Barrier Bolts:

Note any problems with locks (e.g., inoperable, buried, penta head not in place, penta head misaligned). Note locks or penta assemblies that are missing. Locks and penta bolts should be available during patrols and installed or replaced during the inspection. Missing or inoperable locks should be replaced with the standard lock. Report if the deficiency still remains.

6.10.1 Temperature Readings Taken with an Infrared Thermometer or Camera

Temperature readings should be taken for all under ground equipment. Temperature readings with a greater than 30 degree Celsius temperature

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difference between similar components (e.g. comparing elbow to elbow) will be recorded as a high priority.

It is important to ensure that the infrared thermometer is reading the proper emissivity of the material it is pointing at (e.g. you can get a 10 degree Celsius difference if looking at rubber versus steel). ny potential problems detected by the infrared thermometer should be noted in the comments section of the apparatus.

6.11 Riser Poles (Dip Structure)

The following checks should be made at Riser Poles and Dip Structures.

The following checks should be made at riser poles:

- Conduit:
  - Conduit clamps
    - No clamps - Urgent
    - <2 clamps - Rehabilitation
  - Broken – with cables accessible - Urgent
    - Cracked - Rehabilitation
  - Conductor – deformed at top of conduit - Rehabilitation
- Terminators:
  - Signs of overheating
    - Melting - Urgent
    - Discoloration - Rehabilitation
- Neutral Condition:
  - Broken or loose – Urgent
  - Signs of corrosion – Rehabilitation

Note: Be aware of primary dips that look like they were installed illegally. This could be a potential power theft situation. If such a situation exists or is suspected to exist, please inform the operations foreman and the Manager of Revenue Protection.

6.12 Assessing Secondary Facilities

Secondary apparatus are to be visually inspected during the Condition Assessment. However, secondary apparatus do not need to be opened unless damage is suspected.

Customer secondary meters on primary poles must be identified and removed.

The following checks should be made at the described secondary facilities.

6.12.1 Cabinet (If applicable)

- Rust – rusting through; superficial - Rehabilitation
- Dented – causing encroachment to limits of approach - Urgent
- Door or lid problems – bonding strap not connected; binding; hinge problems; missing stops - Rehabilitation

6.12.2 Grade

The following checks should be made:

- Equipment depth inadequate – needs raising or lowering - Rehabilitation
- Equipment leaning – excessive - Rehabilitation

6.13 Streetlights

Corrosion of base-plated poles is typically isolated to the pole interior within a narrow band that starts at a point in-line with the top of the exterior fillet weld and extends upward towards the hand hole. Corrosion depth was found to be greatest on the pole’s interior face directly across from the weld toe and it generally tapered off to minimal deterioration within 25 mm (one inch).

Dents are generally the result of automobile impacts and thus are found in the lowest 1 to 2 metres (3 to 6 feet) of the pole. he destructive load testing showed that a small dent had minimal effect on a pole's strength. However, a larger dent, depending on its orientation with respect to pole load, can significantly compromise the load capacity of a pole. If the streetlight is dented, measure the depth by bridging the dent with a straightedge and measuring at the deepest part under the straightedge. If the dent is more than 38.1 mm (1.5") the pole should be identified for replacement.

The Power Line Technician or Municipality can identify painting for a number of reasons rust, graffiti, paint chipping or extreme fading.

All streetlights should be opened and connections inspected for tightness and corrosion. Check grounding lugs and make sure they are in good condition.

Replace any missing doors, or temporarily seal any missing doors and identify them in ArcFM (GIS) for replacement.

6.14 Future Planning

Often there are deficiencies in the distribution system where it is useful to know the quantity and location of various components. Examples of these are described below.

6.14.1 Bird Proofing of Main Line Apparatus (Future)

Birds are most often the highest cause of outages in certain areas. These outages create momentary interruptions and a higher risk of long-term interruptions when they occur on main lines. Bird-proofing main line apparatus and equipment immediately adjacent to main lines will increase overall reliability in these areas and reduce customer complaints regarding momentary and sustained outages. Knowing all of these locations would be very useful to determine the correct effort/budget to correct the areas.

6.14.2 Hot Tap Connectors (Past)

In the 2009/2010 Capital plan there was a new program introduced as part of the distribution rehabilitation program to replace all Hot Tap Connectors with a stirrup. Information including quantity and locations of Hot Taps while planning this program would have been beneficial.

The information described above are examples of projects where it would be beneficial to have this information stored in ArcFM (GIS). Going forward, if required, this information will be identified during the Condition Assessment but will generally not be included in the Rehabilitation package. This information will be stored in ArcFM (GIS) and used for future planning programs. Additional effort like this has to be planned and budgeted for accordingly.

7. Vegetation and Osprey Nest Notification

7.1 Vegetation

Unwanted vegetation has the potential to adversely impact FortisBC's electrical infrastructure, threaten the safety of employees and the public as well as reduce system reliability. Accurate identification of unwanted vegetation on or adjacent to FortisBC's power system enables the company to better understand growth rates and characteristics, predict locations and determine whether or not control is warranted or desirable. By understanding the vegetation along its power line corridors, FortisBC has a better appreciation of the types of control methods needed and the appropriateness of application. FortisBC uses tree risk identification and evaluation processes to make decisions regarding what potential hazards and vegetation threats may be associated with a particular tree or groupings of trees.

Monitoring vegetation and hazard trees is an essential planning and prevention element of the FortisBC Vegetation Management Program. Results from both the Annual Line

Patrol and the Condition Assessment program are used to determine what actions are required to minimize risks associated with the possibility of vegetation coming into contact with distribution lines. If there is hazard trees identified or vegetation encroaching on the lines from either the Annual Line Patrol or Condition Assessment program then the location should be reported to the Right of Way Maintenance Supervisor using the Vegetation Notification Form.

The Vegetation Management Program, which is separate from both the ALP and Condition Assessment Program, will include both ground and air patrols of FortisBC's Distribution Networks as outlined in the FortisBC Vegetation Management Program.

7.2 Osprey Nest

Osprey frequently build nests on distribution poles. Bird contacts on distribution lines/equipment can cause outages. These outages create momentary interruptions and a higher risk of long-term interruptions when they occur on main lines.

If there is an Osprey nest identified that is encroaching on a Distribution line from either the Annual Line Patrol or Condition Assessment program then the location should be reported to the Environmental department and tracked in Arc FM (GIS).

8. Reporting Structure

8.1 Capture the Information

All information (Test and Treat, Condition Assessment and Annual Line Patrol) obtained in the field will be entered, in the field, with the use of a computer. The computer program has to gather all the required information and transfer that data daily (If a network connection is available) into the FortisBC ArcFM (GIS) software.

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8.2 Required Information

Having sufficient information available for all distribution assets is beneficial from an operational, engineering, and planning perspective. The following bullets outline the minimum requirements for each type of patrol;

ANNUAL LINE PATROL

a. Area patrolled
b. Date Annual Line Patrol person was on site
c. Who did the Annual Line Patrol

TEST AND TREAT

a. Pole shell thickness and actions required (Replace urgently, Red Tag, Blue Tag) as per Appendix 1 (M10-04, FBC In-Service Wood Pole Inspection and Re-Treatment)
b. Type of fumigant(s) (rot/insect) added to the pole
c. Date test and treat person was on site
d. Who did the test and treat

CONDITION ASSESSMENT

a. Enter the corrective standard structure(s) and/or material to remedy the overhead/underground deficiency, for example, 2523-1, 1492-1, 5010453, etc.
b. Enter a rating between 1 and 4 for the following: Crossarm, Pole, Padmount Transformers and Switching Cubicles

   1 - Fail - Urgent Repair

   2 - Poor - Include in Rehabilitation package

   3 - Fair - Will last another eight year cycle

   4 - Good - Will last multiple cycles

   Note: The rating system is in place for planners so they can determine how many structures are going to fail during the next rehabilitation cycle. For example; if the assessor's best judgement outlines that the pole will last one more cycle (8 years) but will not last two more cycles, the pole will be flagged as a “3” and will probably be replaced in the following rehabilitation cycle. Having this information available during the planning stage of the project will allow planners to determine more accurate budgets for the rehabilitation program.

c. Enter already established units for how the pole will be set, i.e. blasting, back hoe, crane, hand dig, etc.

d. Enter if flaggers are required to replace the pole

e. Enter if work can be done hot or cold

f. Enter if environmental considerations are required

g. Enter if a special permit is required for work

h. A comment box is required to communicate certain things from the field to the designer such as anchoring and sag specs, ground clearance problems, etc.

i. Who did the Condition Assessment

j. The date the Condition Assessment was done

k. If the assessor thinks this deficiency would be better captured under a rebuild instead of rehabilitation

8.3 Deficiency Tracking and Updating

Once the deficiencies for the asset have been remedied, the As-built process will need to be adjusted such that the deficiency information is removed from ArcFM (GIS) and no outstanding actions are reported for that asset.

All other information from this process will remain in the system until the next condition assessment cycle at which point it will be overwritten.

8.4 Reporting

At any time a report from ArcFM (GIS) can be generated between two points or within the polygon areas outlining;

a. A structure by structure list of outstanding deficiencies, as outlined in section 8.2 under Condition Assessment such as crew hours, equipment required, material, flaggers, special comments, etc.

b. Historical information for planning purposes. The following should be tracked and able to report on a feeder by feeder basis: Shell thickness, vintage of all poles, and how many of them were replaced or stubbed in previous rehabs. This will help planners determine better budgets for upcoming years' rehabilitation.

c. A feeder summary report of deficiencies outlined as urgent repairs or rehabilitation.

d. A feeder summary report on an annual basis to display equipment replaced during any given years' rehabilitation.

e. A feeder summary report with treatment type, units, quantity inspected.

f. A summary of the streetlight type and quantity by feeder.

8.5 Rehabilitation Package

The rehabilitation package will be prepared by engineering and will be laid out as follows:

- Project Work Summary
- Project Estimate
- Project Bill of Materials
- Telus Summary
- 3rd Party Cost Summary (Excavation, Blasting, Flaggers, etc)
- Standard Drawings
- Structure Location Map
- Structure Details

Each structure detail will have one, 8.5"X11" page per location and include the following:

a. Pole identifier with XY coordinates

b. A route map to get to the pole

c. A Bill of Material and costs of material

d. A work summary/comments from designer

e. Crew hour summary
f. Equipment summary (hoe, crane, blasting, etc)
g. As-built template and commenting section on back of sheet
h. Picture if easily implemented
i. Designer's name
j. Date design package was completed and issued
k. Telus transfer time tracking, cost and materials
l. Permits/notifications (customer, Ministry of Transportation, flagging)
m. Revision tracking area

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9. Vegetation Notification Form

Customer Name: ______________________ Date ____________
Address: ______________________
Phone Numbers: Home ____________ Business ____________
Location of tree(s) causing concern:

Assessing Vegetation Control Responsibility:

Type of circuit affected: ☐ Secondary or service conductors ☐ Primary (distribution) ☐ Primary (transmission)

Is the tree (s) located on:
- ☐ Customer's (private) land
- ☐ Other's private land ____________
- ☐ Public land (e.g. MOH, Crown

Is the tree (s) affecting:
☐ Existing FortisBC facilities ☐ New Construction ☐ Customer-owned facilities

Referring to the table summarizing responsibility for vegetation control, the tree control responsibility is:
- ☐ - the customer or facility owner's or
- ☐ - FortisBC or
- ☐ - a field check is required for clarification

Advise the customer of trees that are the customer's responsibility to control. For trees that are FortisBC's responsibility to prune or remove, or that require a field check, forward the completed form to vegetation management personnel. Advise the customer someone will investigate the problem.

* Table summarizing responsibility for vegetation control:

	Type of Circuit	
	Primary	**Secondary**
Existing Facilities		
* Private Land	FortisBC	Customer
* Public Land	FortisBC	FortisBC
New Construction (initial clearing)		
* Private Land	FortisBC	Customer
* Public Land	FortisBC	Customer
Customer-owned Facilities		
* Private Land	facility owner	facility owner
* Public Land	facility owner	facility owner

Action taken (see notes on the bottom of this form):
- ☐ Customer advised tree control is the customer's responsibility (no further action required); or
- ☐ Form directed to vegetation management personnel for further review.

For tree problems that require further review:
Customer contacted by: ____________ On (date): ______
Site visited by: ____________ On (date): ______
Action required: ____________

Problem resolved by: ____________ On (date): ______

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10. Definitions

Apparatus: In ArcFM (GIS), apparatus include transformers, capacitors, and all oil-filled equipment.

Corrective Planned Maintenance: Maintenance performed to bring an asset back to standard functional performance. Trigger by predictive maintenance.

Device: In ArcFM (GIS), devices include bypass switches, cutouts, airbreaks and modular oil-filled switching terminals (MOST).

Emergency Corrective Planned Maintenance: Maintenance performed to bring an asset back to standard functional performance requiring immediate corrective action. Trigger by predictive maintenance to address safety, environmental, or economic risk caused by equipment breakdown.

Exception Reporting: Reporting only information or data that is outside a defined set of parameters for a specific piece of equipment or system.

Known Defects: Identifying equipment or systems that may be potential causes of failure based on information received from manufacturers, other utilities or outage statistics.

Predictive Maintenance: Visual inspection of facilities taking measurements and observations of components or systems. Interpreting and acting on the results by initiating corrective planned or emergency maintenance.

Qualified Employee: Means a power line technician trained and experienced to work safely on energized electrical equipment or lines in accordance with the requirements of the safety rules while performing duties assigned by an employer.

Rehabilitation: Corrective planned maintenance required within 2 to 12 months to address concerns that will be a safety, environmental or system concern prior to the next patrol or inspection

Special Requests: Information required by maintenance planning on a one-time basis due to special circumstances, data requirements or for bundling of tasks for cost effectiveness.

Supporting Structure: In ArcFM (GIS) supporting structures include poles, pedestals, vaults, standards, and all hardware attached.

Urgent: Emergency corrective maintenance that must be done immediately to care for safety, environment or system integrity. The completion of high priority repairs is the accountability of Power Line Technicians. If the patroller cannot correct the deficiency immediately, it is the patroller’s responsibility to communicate the deficiency to Dispatch. Maintenance work that has been completed must be documented in ArcFM (GIS).

Appendix 1

FortisBC Wood Pole Testing and Re-Treatment, In-Service Document

FortisBC

Wood Pole Testing and Re-Treatment In-Service

Based on Wood Pole Pest Management Plan under the Integrated Pest Management Act

Table of Contents

1.0 Introduction

The testing and treatment of wood poles involves an evaluation of the integrity of the pole's physical characteristics and serviceability despite deterioration or damage, and taking measures to prolong the service life.

FortisBC has two main treatment groups of poles in service.

a) **Full Length Treated** – where the whole shell of the pole has been impregnated with Pentachlorophenol (Penta) or Chromated-copper-arsenate (CCA) preservative. The species of poles usually treated under this treatment group are: Western Red Cedar, Lodgepole Pine and Douglas fir.

b) **Butt Treated** – where the butt of the pole (including 0.6 m to 1.2 m above ground line) has been impregnated with Creosote or Pentachlorophenol (Penta) preservative. Incising is often part of the treatment. The species of poles treated under this treatment group is usually Western Red Cedar.

Untreated poles can also be found in the service area.

Decay fungi (i.e., plants that feed on wood) can destroy the structural integrity of wood. Fungi require water, air, favourable temperature, and food in order to propagate and survive. Wood with moisture content below 20 percent usually is safe from fungi. When wood is submerged in water or buried deep in the ground, air is eliminated and fungal growth is minimal. Freezing temperatures stop fungal growth but seldom kill it.

The service life of wood poles is influenced by many factors such as wood species, initial preservative treatment, climate, location, and maintenance practices.

- Full-length treated poles generally suffer little decay during the first 20 years of their life.
- Butt treated poles show signs of decay on the untreated shell earlier than the full-length treated poles (15 years).
- Untreated poles have a considerably shorter life span than the full-length and butt treated poles. An untreated pole could decay at the ground line in 5 to 10 years.

1.1 Scope

This document outlines requirements and guidelines for inspecting and retreating wood utility poles owned or maintained by FortisBC.

1.2 Using This Document

It is the responsibility of persons using this document to seek clarification, where needed, from the Maintenance Planner.

2.0 Benefits of Pole Testing and Treatment

At regular intervals, FortisBC conducts testing and treatment of all in-service wood utility poles that are owned or operated by FortisBC.

The benefit of maintaining wood poles is to extend their service life, thereby minimizing costly replacements. The testing and treatment methods used are designed to ensure public and employee safety, provide appropriate reliability, and prevent high consequence failures.

3.0 Maintenance Policy for In-Service Poles

3.1 Inspection

In-service wood poles shall be periodically inspected and maintained. Poles 16 years of age and older will be inspected as outlined in this document and, if necessary, will receive remedial treatment as outlined in this document. Poles newer than 15 years of age will only receive an aboveground visual inspection (refer to section 5.3) unless extraordinary conditions apply. Reliability-centred maintenance principals of tracking degradation within a species, treatment, service territory, or maintenance program may alter inspection cycles to be more suitable and cost-effective. Recommend treating all non cedar poles with in 8 years, new poles may show signs of decay before 15 years because they are second growth. Growth rings are further a part.

3.2 Maintenance Cycle Requirements

All inspected poles shall receive a full inspection that includes, but is not limited to:

- Visual inspection
- Sounding
- Drilling/boring

The contractor shall determine the appropriate remedial treatment based on the specifications outlined in this section.

4.0 Roles and Responsibilities

The key personnel involved in FortisBC's Pole Testing and Re-Treatment program are the Maintenance Planner and Pole Inspection Contractors.

4.1 Maintenance Planner

The Maintenance Planner is accountable for the development and general administration for the In-Service Wood Pole testing and Re-Treatment program.

The primary responsibilities associated with administration for the In-Service Wood Pole testing and Re-Treatment program are:

- Coach Line Construction Manager and inspection contractors on standards to work to
- Combine and develop budgeting and work plan submissions
- Ensure communication of work planned and completed
- Pre-qualify inspection contractors and tender contracts
- Hold relationship with contractor management
- Verify that the inspection contractors carry out the duties within their contract with FortisBC
- Dispute and work quality resolution with Line Construction Managers, and inspection contractors
- Accountable for incident investigation and reporting
- Review program standards and procedures

4.2 Line Construction Manager

The Line Construction Manager ensures the maintenance of in-service wood poles in a condition that supports reliability, integrity and safety. This is accomplished using contracts and contractors performing accepted inspection and test methods.

Line Construction Managers verify contractor hours and units reported, aid in customer contacts, and resolve customer complaints and damage claims. Line Construction Managers also assist with identifying work areas and scheduling of crews.

Specific to the monitoring of the pole test and re-treatment program, the Line Construction Manager must:

- Have knowledge and/or experience in the following areas:
  - Powerline operations and electrical safety
  - Contract Management
  - Customer/ stakeholder dispute resolution
  - ArcFM
  - Safety procedures and audits
  - Internal wood Pole testing and Re-treatment documents (e.g. this document)
  - Acts, regulations and company policies and procedures governing pole testing and re-treatment work
  - Inspection crew capabilities
  - Access requirements for working in and around gas installations

The primary responsibilities associated with the Line Construction Manager with respect to the pole test and re-treatment program are:

- Ensure contractors work in safe manner meeting both FortisBC and government regulations
- Ensure the necessary permits, licenses, or permissions are obtained for entering onto property to conduct pole inspection and testing work
- Notify county, municipal or regional district authorities and owners of work planned for their jurisdictions.
- Perform safety and work quality audits on pole test crews
- Audit the standards conformance and compliance of the inspection contractors to their contract with FortisBC
- Check and verify invoices
- Support incident and accident investigations and reporting relevant to pole inspection work performed for FortisBC
- Resolve customer inquiries and complaints regarding pole inspection, testing and re-treatment
- Maintain working relationships with internal stakeholders including Network Services Native reserves

4.3 Inspection Contractors

Work for inspection contractors is identified within ArcFM. The work is normally paid on a unit price basis.

When an inspection contractor moves into a new area, they should make the opportunity to meet the local contacts.

Crews submit a weekly update of the units completed to the Maintenance Planner. Contractor personnel enter the date completed on ArcFM for locations completed that day and send ArcFM packets on the completion of an RCM circuit to the Maintenance Planner. Send in on completion of area

4.3.1 Contract Adherence

The Contractor must adhere to the Wood Pole Test and Treat Agreement contract at all times. Failure to comply with any of the requirements of the contract without prior authorization will result in a crew warning or shutdown.

4.3.2 Crew and Equipment

The Contractor assumes the full responsibility for having the proper equipment required by the federal, provincial and local laws for the work covered by the contract. The Contractor is also responsible for meeting all safety regulations.

The Contractor is responsible for ensuring that their personnel are familiar with this manual, all safety legislation, and any other pertinent acts that may apply to their work. FortisBC is not responsible for training Contractor crews, however, the Line Construction Manager or Maintenance Planner can be contacted to clarify any matters.

The crews must be courteous to customers and quickly process any inquiries, complaints, or damages according to the proper procedures.

4.3.3 Standards of Work

Inspection contractors are accountable to ensure they have the appropriate permissions and approvals to undertake inspection activities. Approval to do the work is given by FortisBC, with contract specific requirements for obtaining individual access.

The contractor is responsible for identifying any potentially hazardous situations and using good judgement to avoid them.

4.3.4 Obtaining Licenses and Permits

The contractor is responsible for obtaining all licenses and permits required for performing their work. The contractor is responsible for knowing which permits are required and for ensuring permits are in place before commencing work. All conditions of the current Wood Pole Maintenance Pest Management Plan and permits are to be followed. Use records and annual report submission shall be submitted to FortisBC Environment by December 31 of the treatment year in accordance with Section 39 of the IPM Regulation.

Inspection contractors are accountable for having the proper personnel licenses required by federal, provincial, and local laws for the work covered by the contract.

The contractor is responsible for obtaining permits not directly related to inspection work (for example, load or road permits, and municipal dumping permits).

4.3.5 Minimum Competency for Pole Testing and Treatment Application

The minimum qualifications for individuals undertaking pole test and re-treatment will be approved by the Line Construction Manager but should include:

- Prior experience working under a competent tester prior (e.g. evaluating a minimum of 5000 poles under the direct supervision of a competent tester) 6-8 months
- Knowledge of the requirements of this document, the Pole test and Treat Agreement, and applicable regulations
- Knowledge of Provincial and Federal legislation for pesticide transportation, storage, handling, application, and use pesticide applicator certificate

5.0 Inspection Procedures

This section describes the procedures to be followed by trained personnel doing maintenance inspections of in-service poles and stubs. The inspections include the following: above ground inspection, partial below ground inspection or full below ground inspection. The requirements in of when to replace or stub a pole are also included in this standard.

Strength calculations, outlining mathematical calculations to determine pole integrity, are covered in Section 5.3. As well, the application of external and internal treatments is covered in separate sections.

5.1 Safety Hazards Encountered During Pole Testing and Treatment Program

Perform a visual inspection while approaching each pole, and while working in the vicinity of the electrical system, to detect possible safety hazards, including broken insulators, loose wires, loose or broken guy wires, leaning poles, broken ground downleads (COULD BE ENERGIZED), or “Hot” poles due to insulator leakage.cut outs

Hazards encountered that pose a danger shall be handled as follows:

Immediate Danger

Safety hazards that could pose an immediate danger require the pole inspector to remain on site and secure the area affected by the danger.

The pole inspector shall take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If assistance is required, the pole inspector shall contact the PIC or the Line Construction Manager and remain on site until qualified assistance or relief arrives.

Danger Pole

Poles that are not an immediate hazard but suspected of failing within one year must be reported to the Line Construction Manager And the contractor delegate

No Immediate Danger

Safety hazards encountered that do not pose an immediate danger require the pole inspector to take whatever steps within their qualifications and authorization, utilizing approved work methods and equipment, to eliminate or reduce the hazard.

If other resources are required to eliminate the safety hazard, the pole inspector shall document the hazard in ArcFM, and contact the PIC as soon as practically possible, relaying details of the hazardous situation.

Other deficiencies not considered to be a safety hazard shall be noted in ArcFM, as covered in this document.

5.2 Preparation

When work is to be done in close proximity to a home or on private property, the property owner shall be notified as to what is being accomplished. Brush will be removed from around the pole to allow for proper excavation and inspection, unless the property owner denies permission for removal. If permission is not granted, the pole will be sounded and bored, and reported.

CAUTION: Care must be taken to ensure the ground wire is not broken, and not to break the ground wire or to disconnect it from the ground rod. Ground wires must be carefully pulled away from the pole so as not to interfere with the work and restored to original location when work is completed.

5.3 Above Ground Inspection

An inspection of all poles shall be made from the ground line to the top, before excavating for the below ground line inspection.

Above ground inspections include:

(i) visual inspections to identify:

- lateral breaks or cracks
- above ground decay pockets
- excessive spur cut
- woodpecker holes
- broken ground wires
- signs of insect infestation
- shell rot
- pole top rot
- rotten or split top
- physical damage
- broken crossarm or hardware
- fire damage cut outs

(ii) probing and sounding to detect internal decay;

(iii) drilling into the pole at ground line near the largest check, and at other locations where internal decay is suspected.

If the pole is obviously not suited for continual service due to excessive shell-rot or other serious defects, it shall not be excavated, but shall simply be reported as a reject and recommended for replacement. If judged serviceable, it shall be excavated and further inspected. Ground line is from the ground up to 12" above

This section is broken down into external and internal inspections.

External Inspections

External inspections are a visual inspection of the above ground zone of a pole or stub.

Defects that are too high up the pole to be properly inspected shall be documented in ArcFM, and so a follow-up inspection can take place by a person qualified to climb the structure and inspect the defect.

Visual inspections above ground identify the following defects:

- *Shell Rot/Damage*: Such things as shell rot, lightning damage, physical damage, and fire damage can significantly reduce pole strength. Poles shall be identified for replacement based on the presence of shell rot or damage if the following conditions are true:
  - Poles with a circumference greater than 1200 mm shall be marked and reported for replacement if shell rot or damage is greater than 50 mm deep for more than 30% of the circumference.
  - Poles with a circumference between 775 mm and 1200 mm shall be marked and reported for replacement if shell rot or damage is greater than 25 mm deep for more than 30% of the circumference.
  - Poles less than 775 mm circumference shall be marked and reported for replacement if shell rot or damage is greater than 13 mm deep for more than 30% of the circumference. Rare in FortisBC area
- *Breaks*: Lateral damage (a break) occurs when a pole is over-stressed (e.g., after being struck by a motor vehicle), and can render the pole unsafe. A cracked pole should be recommended for replacement and reported immediately to the Line Construction Manager.
- *Woodpecker damage*: Generally, small woodpecker holes, particularly those that follow checks, do not significantly reduce the strength of a

pole and do not have to be reported. A very large woodpecker hole, or several smaller woodpecker holes at the same general location can weaken the pole significantly, and may be an indication of insect infestation and/or unsound wood, and must be reported.

- *Insect infestation*: Insect infestation can be recognized by: obvious insect activity, piles of sawdust or sawdust-like material, round and oval holes on the surface of the pole, or galleries under the surface of the wood. Areas infested with insects shall be investigated by boring and probing

Internal Inspections

- *Probing*: Probing is used to detect decay in checks and pockets and can be done with a screwdriver or stiff wire. Rot should be suspected when wood yields after firm pressure is exerted on the wood within deep cracks and pockets. Suspicious areas shall be investigated by boring. **Note:** Jabbing sharpened bars into the surface of a pole or stub is not recommended as this may damage fungus resistant wood and allow rot to start in less resistant areas.
- *Sounding*: Sounding is used to detect internal decay of a pole or stub. Sounding shall be performed on all inspected poles. A hammer is used to strike the surface of the pole from the ground line to as high as can be reached. This shall be repeated for each quadrant of the pole. A sharp ring indicates sound wood, whereas a hollow sound or dull thud indicates hollow heart or decay. Seasoning checks, internal checks, and shell rot can affect the sound. Suspicious areas shall be investigated by boring.
- *Boring*: Boring is done to determine the condition of the inner wood. Holes should be drilled using a bit diameter that is suitable for the treatment that will be applied to the pole at the following locations:
  - for a stubbed pole: near the upper and lower bands or bolts in both the pole and the stub;
  - where sounding or probing indicates a possible defect;
  - at locations of insect infestations;

When boring takes note of:

- the rate of penetration of the drill: sudden collapse of the wood being drilled indicates decayed wood or hollow heart;

  - powdery wood particles indicate insect infestation or dried out decay;
  - discoloured wood particles (such as severe darkening) almost always indicates the early stages of internal decay; in the late stages of decay the wood may become soft and spongy, stringy or crumbly; care must be taken not to mistake sound wet wood for decayed wood, colour is a good identifier; sound wood usually has a clean, fresh, resinous smell; a musty or mushroom smell may indicate decay.

- *Shell thickness:* If internal decay is found above ground line by drilling, two additional holes shall be drilled, equally spaced around the circumference of the pole at the same horizontal plane. Shell thickness shall be measured through the inspection holes with a shell thickness indicator tool or other appropriate tool. Note the shell thickness measurements in ArcFM. Average shell thickness shall be determined using a minimum of three measurements taken along the same plane of reference on a pole.
  - If average shell thickness is less than 2.5 cm (1 inch), the pole shall be marked and reported for replacement. 3”or less of shell above gl is a reject
  - If average shell thickness is greater than 2.5 cm (1 inch) and less than 6.5 cm(2.5 inch) the pole shall be marked and reported for stubbing.3” to 1” below ground line is a stub Deep Decay poles are marked for stubbing
  - **Note:** Poles must be appropriately internally treated when stubbed.

5.4 Below Ground Inspection

Note: Do not excavate around a pole if it is unsafe to do so (e.g., the pole is rotted through at ground line, or a pole is not set deep enough in the ground). The minimum setting depth is 10% of the pole height plus two feet. Unsafe poles shall be reported immediately to the Line Construction Manager.

Below ground inspections include:

a) excavating around a pole (as required for proper assessment and treatment of the pole);

b) probing and sounding to detect internal decay;

c) confirming internal decay by drilling;

d) drilling for internal treatment;

Internal Inspection

Note: All bored holes shall be plugged with a removable / reusable, brightly coloured, tapered plastic plugs with 1.5 mm interference fit, or approved substitute. The plugging of the holes is to reduce the possibility of the bored holes from serving as an entry where practical; drill holes from previous inspections are to be re-used as part of the following boring requirements: ¾ " drill bits with 15" of shank

- A minimum of three holes shall be drilled in the following locations:
  - Poles and wood stubs shall have three divots dug, so that one inspection hole can be drilled at 30 – 38 cm below ground line and two inspection holes can be drilled at 7.5 - 15 cm below groundline. The holes shall be located 120 degrees apart in section at an angle of 45-60 degrees from the pole in profile.
  - Both the original pole and a wooden stub shall be drilled in the vicinity of either the upper and lower bands or bolt points.
  - Poles shall be drilled where sounding indicates a possible void.
  - Poles shall be drilled at locations of insect infestations.

5.5 Backfilling and Clean-Up

After inspection and treatment, the excavated area shall be refilled and firmly tamped to avoid the possibility of subsequent settling. Do not backfill loose articles, turf, garbage or loose asphalt. To prevent damage to the bandage, protect the bandage with a shovel during backfill.

No debris, loose dirt, etc. is to be left in pole area in the case of city or private property poles. Private property turf, bushes, etc. are to be replaced with care.

5.6 Identification and Tagging of Work Completed

Work Performed

All inspected poles shall be marked with a tag identifying the inspection company, and the year the work was completed. Tags shall be placed 2.1 m above ground line on the roadside of the pole. All tags shall be attached to the pole with screw shank aluminum roofing nails. Completed missing pole sheets and marked up maps are to be submitted to the

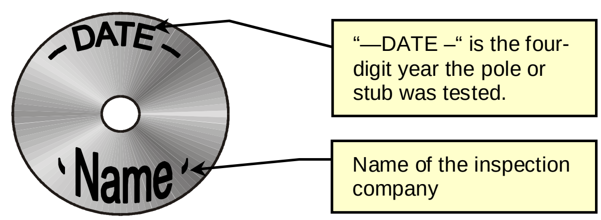
Senior Maintenance Planner as completed for data entry. Extra poles sheets

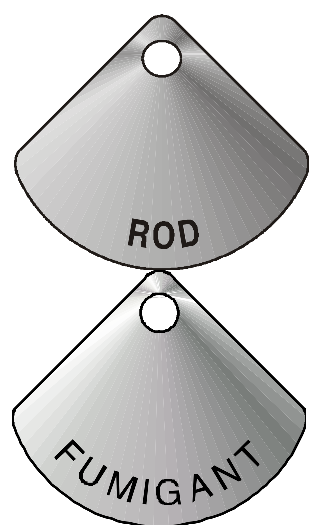
Rejected Poles

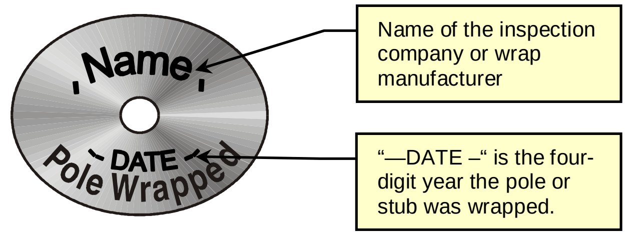
Poles that are recommended for replacement shall be identified by 3.8 cm red nylon webbing with white “XX” lettering, securely attached to the pole approximately 1.8 m above ground line. With a 3” -3” red square tag over the ribbon

Poles that are recommended for stubbing shall be identified by 3.8 cm red nylon webbing with white “XX ST XX” lettering, securely attached to the pole approximately 1.8 m above ground line. With a blue 3”-3” square tag over the ribbon

All inspected poles shall be tagged as outlined in this section. The tagging shape indicates appropriate pole condition and treatment.

Pole or stub was inspected:	

Internal decay, treated with Boron, CuNap, Fumigant: data is entered in arc fm	

Pole has been inspected, pole wrap installed at groundline: data is entered in arc fm	

Green 3"-3" square tags mark No Treatment Zones

Pole requires replacement, **DO NOT CLIMB:**


Pole must be stubbed. Pole found to be weakened due to rot, insects or mechanical damage. **CLIMB ONLY IF SUPPORTED:**


The pole tester also marks poles identified for replacement or stubbing with a 7.62 cm by 7.62 cm colour-coded plastic tag. Tags are nailed to the nylon, on the side of the pole normally visible to an approaching line worker.

<u>Colour-coding for pole stubbing or replacement tags:</u>

The following colour coding is used on the 7.62 cm by 7.62 cm colour-coded plastic tags, supplied by the Maintenance Planning and Brushing group:

Tag Colour	Tag Installation Year	Year Stubbing or Replacement to Occur
Red replace		
Blue stub		
Green ntz		

Note: There may be tagging outstanding from earlier pole marking programs.

6.0 Pole Treatment Application

If the pole is serviceable, pesticide treatments are used to remediate existing as well as prevent further structural damage caused by wood rot and wood-boring insects and fungus. This includes poles identified as requiring stubbing.

Required remedial treatments are based on the condition of the pole and on the pole vintage.

External treatment involves the application of a partial (18” wide) or full (24” wide) preservative bandage below the ground line. The ingress of fungus and insects into the poles is prevented using this treatment type. Does very little for internal decay

Internal treatment is applied to poles to arrest internal decay or exterminate insects. Holes are drilled in the sides of the pole above and below ground. The internal treatment is applied by injecting or inserting the chemical into the drilled holes.

All chemicals used on, or in, FortisBC power poles must be registered for use in Canada by Pest Management Regulatory Agency (PMRA), and approved by FortisBC, as for use on wood products as listed in the current Pest Management Plan. Follow manufacturer’s instructions. Refer to Appendix A for a listing of currently approved preservative bandages, remedial treatment rods, fumigants, cavity floods, and insecticides.

6.1 Bandage Treatment (External) Treatments should not be determined by the poles vintage

External groundline treatment shall be performed as follows:

- **Poles of 1959 vintage and older:** Poles of this age shall not receive any external ground line treatment.
- **Poles of 1960 - 1979 vintage:** Poles of this age identified by the inspection program, shall receive an external ground line treatment. CCA-treated poles do not receive the external ground line treatment unless there is evidence of decay.
- **Poles 16 years old to 1980 vintage:** Poles of this age shall receive an external ground line treatment only if the shell is “punky” or showing signs of shell rot at the ground line.
- **Poles 15 years and newer:** Poles in this range shall not receive external ground line treatment unless extraordinary situations apply.

6.2 Internal Treatment

Internal treatment shall be applied as follows:

- **Poles 16 years old and older:** Install remedial treatment rods and borate-based liquids (not copper napthenate) at the same time only if the pole has moisture content of 25% or greater. Fumigate if the pole if the moisture content is below 25%. All poles of this vintage shall receive remedial treatment. If a void is present one of the following shall be performed:
  - Liquid wood preservative (cavity floods) shall be flooded directly into the void until the cavity is full.
- **Poles 15 years and newer:** Poles of this age shall not receive internal inspection unless extraordinary conditions apply.

7.0 Legal and Other Requirements

The following list provides a summary of some of the acts, regulations, standards, and practices that affect pole inspection work:

- Integrated Pest Management Act
- BC Transportation Highway Accommodation
- Agricultural Chemicals Act
- Clean Water Act
- Code of Practice for Watercourse Crossings

- Environment Code of Practice for Pesticides (ECPP)
- Forest and Prairie Protection Act and Regulations
- Land Surface Conservation and Reclamation Act
- Occupational Health and Safety Act (OHSA)
- Pest Control Products Act
- Pipeline Act
- Transportation of Dangerous Goods (TDG) Act and Regulations
- Transportation of Dangerous Goods Control Act
- Weed Control Act

8.0 Reporting – Using ArcFM

The attributes, testing, and treatment information for all inspected poles shall be recorded, updated, or confirmed in FortisBC Corporate Mapping System (ArcFM Mobile).

Contractors are expected to perform the follow tasks in ArcFM Mobile:

- Update basic pole information including: Pole Stamp Date, Height, Class, Species, Type (Transmission/Distribution), Material (Wood, Steel, Concrete), usage type (Secondary, Primary) and Pole Treatments.
- Identify any required and completed actions
- Update inspection information regarding test results of the pole including Circumference, Shell Thickness (East, South and North Face) and any comments

Contractors are expected to keep a listing of all mobile sessions submitted to FortisBC for processing and are to ensure naming of mobile sessions is clear and descriptive.

Contractors are expected to follow the procedures outline in “Inspection (pole and Line Patrol) ArcFM Mobile Workflow” for updating information in ArcFM mobile.
FortisBC will supply the contractor with the necessary software to run reports on completed sessions before the sessions are submitted

Reasonable justification shall be given, in the comments section, whenever a pole that has been specified by FortisBC for inspection may not be tested or treated. Justifications include:

- pole has no FortisBC equipment on it;
- pole is commercially butt treated and less than fifteen years old;
- pole is in water;
- pole is inaccessible.

No treatment zones
Difficult digging due to brush or roots does not warrant deferring inspection or treatment.

Any poles not scheduled for testing, treatment, but obviously requiring inspection should be inspected. For example: poles in the test / treat age group not shown on FortisBC maps; poles affected by grade changes; and poles affected by vehicle damage. Insect damage, checks

8.1 Creation of Sessions

- A new session must be created at minimum of once per day.
- A new session must be created if the computer crashes or other odd behavior is experienced.

8.2 Submission and Syncronization

- Contractors receive the ArcFM Mobile application and are required ensure that information is uploaded and downloaded from ArcFM Mobile machines at a minimum of a weekly basis to ensure that the data on the mobile machines is current and that information collected on the mobile machine is sent to FortisBC. This will require that the contractor connect to the FortisBC computer network at one of the FortisBC offices in the service area.

8.3 Setting Work Order Information

- All edits in ArcFM are tracked to a workorder that identifies the job and to a salvage workorder which allow assets to be removed from FortisBC's asset base. FortisBC project managers should provide a listing of workorders for the job

8.4 Indicating Poles and Pushbraces Need to be Removed

- Sometimes people will come across poles or pushbraces that exist in ArcFM but do not exist in the field. When this is found the users are expected to identify the poles that do not exist so that they can be removed properly from the FortisBC system. This is accomplished through simple map markups using ArcFM Graphics

8.5 Adding a Missing Distribution Pole, Pushbrace or Transmission Pole

- If a pole is found in the field during the audit and is not found in the mapping system, it can be added and related records added and inspection conducted to the pole to ensure that all pole and related information is complete. Also, pole inspection information may be added to the pole as well.

9.0 Monitoring, Measuring, and Continual Improvement

9.1 Monitoring

IPM Regulation requires a monitoring program to evaluate the effectiveness of the pesticide use under S 58(f). Section 69.(2) requires pre-treatment and post treatment observations of the treatment area to evaluate the effectiveness and impact of each pesticide use.

The following monitoring methods are undertaken to control critical activities:

Aspects and Critical Activities	*Monitoring Method*	*Primary Responsibility*	*Monitoring Frequency*
Pole integrity evaluation	• DOSS • Incident database • ArcFM	• Maintenance Planner	Ongoing
Pole testing / re-treatment	Field audit	Line Construction Manager	Weekly during contract term
Pesticide application and handling	Visual audit	Line Construction Manager	Weekly during contract term

9.2 Auditing

The Line Construction Manager performs safety and work (quality) audits on inspection contractors.

9.2.1 Inspection Contractors

Inspection contractors receive:

- A detailed audit twice per year: one at start-up and one part way through the contract term (e.g. truck, equipment, tools, qualification of employees)
- A work observation audit (drive-by) at a minimum every two weeks (observe work methods; check for safety items like shields, hard hats, safety glasses). Drive-by audits are not announced.

Quality of work is checked including:

- Compliance with contract and program requirements
- Use of proper techniques and practices
- Proper clean-up of area
- Records completed

Contractors expected to audit their crews regularly (every two weeks) and supply a copy of the audit results to the Line Construction Manager. Audit areas upon completion 2%

9.2.2 Corrective Action

The Line Construction Manager advises the audited party of any nonconformance.

9.3 Continual Improvement

The Maintenance Planner and Line Construction Manager regularly discuss the program, and resolve issues, ensure consistency (where it makes sense to do so), and continually improve processes. Meetings are held with contractor personnel prior to start-up and at the end of the contract period to ensure efficient and effective contract execution.

9.3.1 Inspection Contractor Start-up Meetings

A meeting is held prior to the start-up of a new pole test and treat contract (at no cost to FortisBC). The meeting is held to ensure clarity on the contracted work prior to the fieldwork being initiated. Key topics of concern to both parties are discussed, and time is made available to answer questions or discuss issues raised.

Topics covered could include:

- Goals of FortisBC's pole test and re-treatment program
- Contractor accountabilities
- FortisBC's Health and Safety Policy
- Safe Work Planning, Safety, and Incident Reporting
- Work packages – the information provided to the crew
- Standards and specifications
- FortisBC operations contacts

10.0 Record Location and Retention

Record retention shall be in accordance to FortisBC's record management policies. The chart below summarizes records that may be generated from the pole test and re-treatment program, and provides a retention classification code that corresponds to the records classification system retention schedule.

Records	Location of Records	Retention Classification Code(s)
FortisBC one-Call	Line Construction Manager's files	
Damage claims		
DOSS reports (vegetation contacts causing outages)	DOSS database	
Pesticide application logs	Contractor's files,	
Pesticide licenses and permits	Contractor's files, if required	
Pesticide spill reports	Contractor's files	
Pesticide transportation, handling, storage	Contractor's files,	
Pre and post treatment observations	Contractor files	
Incident reports	Incident Management database and contractor's files	
Licenses and permits	Contractor's files, if required	
Meeting minutes - internal		
Meeting minutes – meetings with contractors (e.g. start-up, quarterly meetings)	Senior Maintenance Planner's files	
Road Use Agreements		
Safe Work Plans • Line Construction Manager • Inspection Contractors	• Maintenance Planning Coordinator's files • Maintenance Planning Coordinator's and contractor's files	
Town/City Agreements		
Inspection Contractor audit (by FortisBC)	Line Construction Manager files	
Inspection Contractor audit (in-house)	Inspection Contractor files	

11.0 Definitions

The following terms are commonly used in the context of wood pole structure maintenance:

Break:	Separation of wood fibres across the axis of a pole (not to be confused with a check).
Butt Treated:	The commercial treatment of the lower part of a pole, from the butt to about 2 feet (60 cm) above the normal ground line. Incising is often also part of the treatment.
Checks:	A V-shaped crack which separates the wood lengthwise along the wood fibres. Checks that extend to the centre of the pole are often caused as the pole dries and seasons. Checks do not reduce the strength of a pole but do serve as avenues for decay spores to enter the pole. Compression wood is the separation above ground of the sap wood from the heart wood Checks that run along bolts create an unsafe condition and shall be documented on the report form. Checks that do not run through an entire pole or along a bolt are common and do not create a pole hazard.
Cross Break:	Separation of wood fibres across the grain, usually caused by mechanical strain. Cracks seriously weaken poles. Not to be confused with a Check.
Creosote:	Certain distillates of tar suitable for wood preservation.
Decay (Biological):	Decomposition of wood substance by organisms such as wood destroying fungi.
Deep Decay:	Decomposition of wood substance by organism occurring below the normal test excavation depth. Internal decay, hollow heart
Defect:	A physical characteristic that reduces the strength of a pole (e.g., bird hole, rot, etc.).
Effective Groundline Circumference:	The measured circumference of a pole, in the ground line area, minus allowances for external decay defects that reduce the strength of the pole.
Exposed Pocket:	A bird hole or a pocket of decay in the side of a pole. May be associated with checks or external damage.
External Decay:	Surface rot, rot in exposed pockets, and insect infested sapwood.
Full Length Treatment:	The commercial treatment of an entire pole using either a Thermal or a Pressure Process.
Fumigant Treatment:	Application of chemical treatment into the pole to arrest and control internal decay or kill insects.
Fungus/Fungi:	Filamentous organisms that obtain their nutrition by degrading other materials, including wood.
Ground Line Section:	That part of a wood pole that is one foot above and two feet below the groundline.
Ground Line	Decay found near the ground line. Depending on soil conditions, decay may

Decay:	start at ground line and extend either up or down a pole.
Heart Rot:	Decay taking place inside the pole and working from the centre to the outside.
Heart Wood:	The inner part of a wood pole that, in the living tree, is no longer used to transport water and minerals from the roots to the leaves.
Hollow Heart:	Internal decay where the pole is hollow or the wood badly decomposed near the centre of the pole.
Mechanical Damage:	Often caused by vehicle / farm implements which results in unsymmetrical damage or cross breaks. A broken pole shall be recommended for replacement and reported immediately to the Line Construction Manager. No Treatment Zones
Pressure Process	A commercial Treatment where a liquid preservative is forced into a pole at a pressure above atmospheric.
Rejected:	A rejected pole is any pole, which upon inspection, is deteriorated below required strength.
Rot:	Decomposition of wood substance by wood destroying fungi.
Sapwood:	The outer part of a pole that, in the living tree, is used to transport water and minerals from the roots to the leaves.
Shell Rot:	Rotten Sapwood normally considered on the above ground part of a pole. When severe, shell rot seriously reduces the remaining pole strength.
Shell Thickness:	Radial thickness of sound wood surrounding internal decay.
Sound & Bore:	Poles designated by the Company and not subject for normal excavation inspection are to be sounded from below ground line to as high as a workman can reach above ground line and bored to locate interior decay.
Split:	Means a separation along the grain forming a check that extends through the pole from one surface to another. In other words, it is a through check.
Stub:	A steel beam or a section of wood pole material that is used to reinforce a pole below the ground line. A stub is 10 - 14 feet (3 - 4.25 m) in length and is inserted into the ground alongside a pole and fastened to it with steel bands or bolts.
Stubbed Pole:	A pole that is supported at ground line with a Stub.
Treated Pole:	A treated pole is any butt treated or full-length treated pole that is 15 years old, or older, and upon inspection, is found to be sound enough to warrant preservative treatment or reinforcement.
Treatment:	Application of a preservative to a pole.
Woodpecker Damage:	Generally, small woodpecker holes that are few and far between, particularly those that follow checks, do not significantly reduce the strength of a pole.

Appendix A – Approved Internal and External Treatment Products

Products must be listed in the current Wood Pole Pest Management Plan:

A.1 Approved Preservative Bandages

Preservative bandages approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- PoleWrap made by North Star Structural Contractors, Ltd.,
- CobraWrap made by Genics Inc.
- Cu-Bor made by Copper Care Wood Preservatives, Inc.

A.2 Approved Treatment Rods

Remedial treatment rods approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- CobraRod made by Genics Inc.,
- Flurods made by NorthStar Structural Contractors Ltd.,
- Impel rods made by Wood-Slimp GMBH

A.3 Approved Fumigants

Fumigants approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- Pole-Fume made by Amvac Chemical Corporation,
- Woodfume made by NorthStar Structural Contractors Ltd.,
- Guardsman Post & Pole Fumigant made by Univar Canada Ltd.,

A.4 Approved Cavity Floods

Cavity floods approved for use on FortisBC's Pole Testing and Re-Treatment program are:

- Tim-bor made by U.S. Borax Inc.
- Boracol made by Wood-Slimp GMBH
- Copper Naphthenate
- GenBor RTU-2 made by Genics Inc.

A.5 Approved Insecticides

Insecticides registered by the PMRA for the effective control of carpenter ants can be used on FortisBC's Pole Testing and Re-Treatment program.

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Appendix 2

Clearance Spreadsheet

Appendix 2 - Clearances Violation Spreadsheet

Date	Time (24Hr)	Clearance Violation Between		Elevation at Each Structure		Span Between Structures	Conductor Type	Weather Conditions	Ambient Temperature	Clearance Where Violation Occurs	PLT	Comments
		Structure #	Structure #									

Appendix J

ISP Expenditures 2012 - 2031

Integrated System Plan Expenditures 2012 - 2031

1	**Generation Projects**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
2	**Physical Infrastructure**																				
3	All Plants Concrete and Structural Rehabilitation	570	617	647	665	686	667	669	705	710	787	801	3,112	778	794	843	871	900	912	906	999
4	Upper Bonnington Spill Gate Rebuild	1,085	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
5	Lower Bonnington Powerhouse Windows	366	8	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
6	Upper Bonnington, South Slocan and Corra Linn Powerhouse Windows	-	430	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
7	Corra Linn Spillway Concrete and Spill Gate Rehabilitation	-	-	7,874	865	1,786	1,728	1,728	1,828	1,840	2,055	1,046	-	-	-	-	1,724	1,783	1,806	1,787	-
8	Upper Bonnington Overflow Spillway Concrete Resurface	-	-	-	-	-	-	-	-	-	-	-	-	-	-	5,833	6,006	6,190	6,282	6,266	-
9	South Slocan Spillway Concrete Repair	-	-	-	-	-	-	-	-	-	-	-	10,519	10,278	10,463	11,110	-	-	-	-	-
10	All Plants Superstructure Upgrade	-	-	-	-	-	-	-	-	-	-	536	529	513	520	553	572	593	603	600	-
11	Lower Bonnington Spill Gate Rebuild	-	-	-	-	-	-	-	-	-	-	-	1,779	-	-	-	-	-	-	-	-
12	Remaining Powerhouse Window Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	958	989	1,002	-	-
13	**Total Physical Infrastructure Projects**	**2,021**	**1,055**	**8,521**	**1,530**	**2,472**	**2,395**	**2,397**	**2,532**	**2,551**	**2,843**	**3,000**	**16,551**	**12,165**	**12,384**	**18,338**	**10,131**	**10,455**	**10,605**	**9,560**	**999**
14																					
15	**Mechanical and Electrical Equipment**																				
16	Corra Linn Unit 2 Life Extension	3,423	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
17	All Plants Station Service	672	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
18	Lower Bonnington and Upper Bonnington Plant Totalizer Upgrade	90	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
19	Corra Linn Unit 3 Completion	722	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
20	Upper Bonnington Old Plant Various Unit Upgrades	1,311	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
21	Upper Bonnington, Lower Bonnington and Corra Linn Plants Automation	-	-	283	291	301	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
22	All Plants Heating and Ventilation	-	-	-	-	-	-	-	-	-	-	895	496	858	485	927	528	993	555	2,973	-
23	Upper Bonnington Old Unit Repowering	-	-	-	-	-	6,961	14,998	17,506	16,099	1,516	-	-	-	-	-	-	-	-	-	-
24	All Plants Fire Water Supply	-	-	-	-	-	-	-	-	-	-	618	612	595	606	-	-	-	-	-	-
25	Mechanical Equipment Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,060	2,279
26	Electronic Equipment Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,060	2,279
27	Corra Linn Unit 3 Generator Rewind	-	-	-	-	-	-	-	-	-	-	-	-	-	347	3,997	-	-	-	-	-
28	Corra Linn Unit 3 Turbine Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	347	3,627	-	-	-	-	-
29	Upper Bonnington Unit 6 Turbine Replacement	-	-	-	-	-	-	-	-	-	-	-	-	-	347	3,627	-	-	-	-	-
30	**Total Mechanical and Electrical Equipment**	**6,218**	**-**	**283**	**291**	**301**	**6,961**	**14,998**	**17,506**	**16,099**	**1,516**	**1,512**	**1,108**	**1,454**	**2,131**	**12,179**	**528**	**993**	**555**	**7,094**	**4,559**
31																					
32	**Dam, Public and Worker Safety**																				
33	Upper Bonnington, Lower Bonnington and Corra Linn Fire Panels	250	259	264	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
34	All Plants Safety and Security	471	475	424	437	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
35	All Plants Fire Safety	-	-	1,001	1,031	1,065	738	-	-	-	-	-	-	-	-	-	-	-	-	-	-
36	All Plants Surveillance and Security	-	-	-	-	-	1,452	1,452	1,538	1,549	-	-	-	-	-	-	-	-	-	-	-
37	Dam Safety Instrumentation	-	-	-	-	-	581	580	613	618	-	-	-	-	-	-	-	-	-	-	-
38	**Total Dam, Public Worker Safety Projects**	**721**	**734**	**1,689**	**1,468**	**1,065**	**2,771**	**2,031**	**2,151**	**2,167**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
39																					
40	**All Plants Minor Sustainment**																				
41	All Plants Minor Sustainment Capital	1,171	1,158	1,203	1,144	1,182	1,142	1,141	1,208	1,216	1,361	1,385	1,371	1,335	1,361	1,452	1,504	1,555	1,575	1,560	1,735
42	**Total All Plants Minor Sustainment Projects**	**1,171**	**1,158**	**1,203**	**1,144**	**1,182**	**1,142**	**1,141**	**1,208**	**1,216**	**1,361**	**1,385**	**1,371**	**1,335**	**1,361**	**1,452**	**1,504**	**1,555**	**1,575**	**1,560**	**1,735**
43																					
44	**Total Generation Projects**	**10,131**	**2,947**	**11,696**	**4,433**	**5,019**	**13,269**	**20,567**	**23,397**	**22,033**	**5,720**	**5,279**	**18,418**	**14,358**	**15,270**	**31,970**	**12,163**	**13,004**	**12,736**	**18,213**	**7,293**

Integrated System Plan Expenditures 2012 - 2031

45	**Transmission Growth**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
46	Okanagan Transmission Reinforcement	2,219	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
47	Ellison to Sexsmith Transmission Tie	7,122	413	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
48	Grand Forks Transformer Addition - Option 1 - Single Breaker	2,491	4,714	1,274	7,549	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
49	Kelowna Bulk Capacity Addition	-	3,720	10,832	11,014	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
50	42 Line Meshed Operation (Huth and Oliver)	-	-	278	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
51	Capacitors at Bentley Terminal	-	-	-	875	4,389	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
52	Reconductor 52 Line & 53 Line	-	-	-	875	1,479	2,288	2,115	-	-	-	-	-	-	-	-	-	-	-	-	-
53	Meshing Kelowna Loop	-	-	2,753	2,798	2,577	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
54	Summerland Substation Transformer Upgrade	-	-	2,152	4,427	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
55	Beaver Valley South Solution	-	-	-	-	758	10,463	10,313	-	-	-	-	-	-	-	-	-	-	-	-	-
56	RG Anderson Distribution Transformer Upgrade	-	-	-	-	3,031	4,061	-	-	-	-	-	-	-	-	-	-	-	-	-	-
57	DG Bell Static VAR Compensator	-	-	-	-	3,031	14,486	19,799	-	-	-	-	-	-	-	-	-	-	-	-	-
58	DG Bell 230 kV Ring Bus	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,554	13,573	18,256	-
59	DG Bell Second 230/138kV Transformer	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,008	6,188	10,550	-
60	Vaseux Lake Third 500/230kV Transformer	-	-	-	-	-	-	-	-	-	-	-	1,777	11,787	18,017	-	-	-	-	-	-
61	Boundary Area Supply	-	-	-	-	-	-	-	-	-	-	-	-	1,536	8,093	-	-	-	-	-	-
62	Reconductor 31 Line (Creston Area)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,307	-
63	Stoney Creek Second Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	17,328	-	-	-	-	-	-	-
64	Playmor 25 kV Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	1,697	3,899	10,016	-	-	-	-
65	Reconductor 50 Line (Recreation-Saucier)	-	-	-	-	-	-	-	-	-	-	-	-	295	-	-	-	-	-	-	-
66	Reconductor 50 Line (FA Lee-Springfield Tap)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
67	Reconductor 51 Line & 60 Line (DG Bell-OK Mission)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	4,608	4,576	-
68	Reconductor 54 Line (DG Bell-Black Mountain)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
69	FA Lee Distribution Transformer Addition	-	-	-	-	-	5,713	6,316	-	-	-	-	-	-	-	-	-	-	-	-	-
70	New Enterprise Substation	-	-	-	-	-	-	9,871	12,608	13,319	-	-	-	-	-	-	-	-	-	-	-
71	Sexsmith Second Distribution Transformer Addition	-	-	-	-	-	-	-	3,072	6,305	-	-	-	-	-	-	-	-	-	-	-
72	Saucier Second Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	3,566	3,848	-	-	-	-	-	-	-	-	-
73	Benvoulin Second Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	3,785	7,966	-	-	-	-
74	Ellison Second Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	2,839	5,011	-	-	-	-
75	Duck Lake to New North Kelowna Substation (78 Line)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
76	DG Bell Distribution Transformer Addition	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	10,041	-
77	New North Kelowna Substation to Sexsmith (80 Line)	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
78	New Central Okanagan Station	-	-	-	-	-	14,283	15,059	7,662	-	-	-	-	-	-	-	-	-	-	-	-
79	Creston Area Capacity Increase	-	-	-	-	-	-	-	-	-	-	-	7,108	6,909	-	-	-	-	-	-	-
80	**Total Transmission Growth**	**11,832**	**8,847**	**17,287**	**27,537**	**15,265**	**51,293**	**63,474**	**23,343**	**19,624**	**3,566**	**3,848**	**8,885**	**37,854**	**27,807**	**10,523**	**22,993**	**5,562**	**24,369**	**45,730**	**-**
81																					
82	**Transmission Sustainment**																				
83	Transmission Line Condition Assessment	522	485	480	547	543	543	457	614	583	628	770	732	597	654	613	771	768	711	841	935
84	Transmission Line Rehabilitation	3,372	2,621	2,509	2,424	2,820	2,562	2,696	2,481	3,053	3,353	3,130	3,753	3,437	3,039	3,601	3,089	3,965	3,809	3,446	4,744
85	Transmission Line Urgent Repairs	594	620	616	622	661	627	616	667	668	764	773	766	726	739	815	831	863	868	853	967
86	Transmission Line Right of Way Easements	400	400	416	423	440	415	409	446	443	518	524	516	484	493	549	560	583	586	572	658
87	6 Line /26 Line River Crossing Reconfiguration	1,185	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
88	27 Line Rebuild (Corra Linn-Salmo)	1,161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
89	21-24 Lines Rebuild (Generation Plants)	2,219	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
90	19 Line/29 Line Reconfiguration	-	791	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
91	20 Line Rebuild (Warfield Terminal-Salmo)	-	4,664	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
92	30 Line Lake Crossing Assessment	-	-	-	802	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
93	30 Line Lake Crossing Rehabilitation	-	-	-	-	1,521	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
94	**Total Transmission Sustainment**	**9,453**	**9,581**	**4,021**	**4,818**	**5,984**	**4,147**	**4,179**	**4,208**	**4,747**	**5,262**	**5,197**	**5,767**	**5,244**	**4,925**	**5,579**	**5,250**	**6,178**	**5,974**	**5,711**	**7,304**
95	**Total Transmission Growth and Sustainment**	**21,285**	**18,428**	**21,308**	**32,355**	**21,249**	**55,440**	**67,653**	**27,551**	**24,371**	**8,828**	**9,046**	**14,652**	**43,099**	**32,732**	**16,101**	**28,243**	**11,740**	**30,343**	**51,441**	**7,304**
96																					
97	**Station Sustainment**																				
98	Environmental Compliance (PCB Mitigation)	11,269	11,553	4,574	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
99	Station Urgent Repairs	818	907	879	977	942	930	907	997	975	1,135	1,142	1,133	1,071	1,094	1,204	1,229	1,274	1,285	1,260	1,429
100	Station Assessment/Minor Planned Projects	1,343	1,354	1,410	1,433	1,489	1,405	1,388	1,510	1,500	1,750	1,772	1,745	1,639	1,669	1,859	1,894	1,972	1,982	1,936	2,225
101	Add Arc Flash Detection to Legacy Metal-Clad Switchgear	539	544	566	1,140	1,184	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
102	Huth Low Voltage Breaker Replacement (2)	-	69	550	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
103	Switchgear Replacement Program (13 kV)	-	-	1,651	-	983	-	1,645	-	1,006	-	-	-	-	-	-	-	-	-	-	-
104	Ground Grid Upgrades	-	-	748	-	790	-	741	-	799	-	937	-	872	-	984	-	1,043	-	1,028	-
105	DG Bell 138 kV Breaker and Voltage Transformer Addition	-	-	338	938	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
106	Osoyoos 63 kV Breaker Additions (2)	-	-	-	364	2,359	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
107	Bulk Oil Breaker Replacements	-	-	-	733	761	720	712	773	768	-	-	-	-	-	-	-	-	-	-	-
108	Station Oil Containment	-	-	-	445	462	852	433	470	910	-	-	-	-	-	-	-	-	-	-	-
109	Minimum Oil Circuit Breaker Replacement	-	-	-	-	-	1,134	1,121	1,219	1,211	1,411	1,429	1,408	1,323	1,348	1,499	1,528	1,590	1,598	1,562	1,793
110	Major Transmission Transformer Replacements	-	-	-	-	-	-	-	1,536	7,971	-	-	-	1,613	8,778	-	-	-	1,953	10,166	-
111	Distribution Transformer Replacements	-	-	-	-	-	714	2,338	-	-	-	873	2,873	-	-	-	933	3,246	-	-	-
112	**Station Sustainment Total**	**13,969**	**14,427**	**10,716**	**6,030**	**8,970**	**5,756**	**9,283**	**6,505**	**15,139**	**4,297**	**6,152**	**7,159**	**6,518**	**12,889**	**5,546**	**5,583**	**9,126**	**6,817**	**15,952**	**5,447**
113																					
114	**Total Transmission and Stations Projects**	**35,254**	**32,854**	**32,024**	**38,385**	**30,220**	**61,195**	**76,936**	**34,056**	**39,510**	**13,125**	**15,197**	**21,812**	**49,617**	**45,622**	**21,647**	**33,826**	**20,866**	**37,161**	**67,393**	**12,751**

Integrated System Plan Expenditures 2012 - 2031

115	**Distribution Growth**	**2012**	**2013**	**2014**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**
116	New Connects System Wide	11,057	10,780	11,446	11,536	12,076	11,298	11,226	12,182	12,117	14,131	14,324	14,094	13,236	13,474	15,017	15,296	15,931	16,008	15,638	17,982
117	Small Growth Projects	1,069	888	1,321	1,752	1,523	1,439	1,423	1,546	1,536	1,788	1,810	1,784	1,679	1,710	1,900	1,936	2,015	2,025	1,981	2,270
118	Distribution Unplanned Growth	924	930	1,031	1,033	1,044	1,007	1,005	1,077	1,072	1,241	1,256	1,239	1,173	1,195	1,320	1,345	1,398	1,407	1,380	1,569
119	Glenmerry Feeder 2-Glenmerry Feeder 1 Tie Line	596	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
120	Ellison Feeder 2 to Sexsmith Feeder 1 Tie	-	1,161	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
121	Hollywood Feeder 5 Upgrades	-	-	1,172	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
122	Kaleden Feeder 1 Capacity Upgrades	-	-	1,330	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
123	Grand Forks Terminal Feeder Addition	-	-	-	-	4,530	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
124	Kettle Valley to Nk'Mip Distribution Tie	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	7,699	-
125	DG Bell Feeder 4 Addition	-	-	-	-	-	-	2,115	-	-	-	-	-	-	-	-	-	-	-	-	-
126	**Total Distribution Growth**	**13,646**	**13,759**	**16,300**	**14,320**	**19,172**	**13,744**	**15,770**	**14,805**	**14,725**	**17,159**	**17,389**	**17,117**	**16,088**	**16,379**	**18,237**	**18,577**	**19,344**	**19,440**	**26,698**	**21,821**
127																					
128	**Distribution Sustainment**																				
129	Distribution Urgent Repairs	2,411	2,315	2,480	2,606	2,605	2,493	2,495	2,693	2,665	3,072	3,114	3,077	2,917	2,975	3,276	3,337	3,467	3,491	3,428	3,885
130	Distribution Line Condition Assessment	1,410	1,398	1,530	1,509	1,569	1,549	1,472	1,635	1,574	1,810	1,924	1,840	1,726	1,841	1,976	2,052	2,073	2,048	2,101	2,348
131	Distribution Line Rehabilitation	5,298	3,517	3,592	3,840	3,865	3,674	3,816	4,164	4,049	4,506	4,487	4,661	4,279	4,360	5,047	5,189	5,268	5,116	4,934	5,899
132	Distribution Line Rebuilds	1,679	1,660	2,214	2,251	2,335	2,222	2,203	2,379	2,370	2,726	2,762	2,731	2,588	2,636	2,907	2,962	3,077	3,098	3,041	3,451
133	Distribution Line Small Planned Capital	726	826	853	867	870	858	839	908	899	1,046	1,054	1,043	986	1,006	1,110	1,131	1,176	1,183	1,160	1,320
134	Forced Upgrades and Lines Moves	2,012	2,413	2,382	2,144	2,462	2,339	2,260	2,425	2,475	2,822	2,851	2,822	2,680	2,719	3,006	3,064	3,185	3,203	3,143	3,575
135	41 Line Salvage and Distribution Underbuild Rehabilitation	2,067	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
136	Environmental Compliance (PCB Mitigation)	-	-	-	-	-	1,611	1,598	1,724	1,718	1,973	1,999	1,977	1,876	1,911	-	-	-	-	-	-
137	**Total Distribution Sustainment**	**15,603**	**12,129**	**13,051**	**13,216**	**13,706**	**14,746**	**14,683**	**15,928**	**15,751**	**17,955**	**18,191**	**18,151**	**17,052**	**17,447**	**17,321**	**17,737**	**18,246**	**18,140**	**17,807**	**20,479**
138	**Total Distribution Projects**	**29,249**	**25,889**	**29,351**	**27,537**	**32,878**	**28,489**	**30,453**	**30,733**	**30,476**	**35,115**	**35,580**	**35,267**	**33,140**	**33,826**	**35,558**	**36,314**	**37,590**	**37,580**	**44,505**	**42,300**
139																					
140	**Telecom SCADA Protection and Control Growth**																				
141	Kelowna 138 kV Loop Fibre Installation	1,212	2,549	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
142	Kootenay Remedial Action Scheme-Install Redundant Backup System	-	-	-	1,166	3,162	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
143	Syncrophasor Data Collection Platform	-	-	-	-	623	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
144	Okanagan Remedial Action Scheme-Install Redundant Backup System	-	-	-	-	-	-	-	3,072	6,100	-	-	-	-	-	-	-	-	-	-	-
145	Princeton to Oliver Fibre Installation	-	-	-	-	-	-	-	-	-	7,133	7,216	-	-	-	-	-	-	-	-	-
146	**Total Telecom SCADA Protection and Control Growth**	**1,212**	**2,549**	**-**	**1,166**	**3,786**	**-**	**-**	**3,072**	**6,100**	**7,133**	**7,216**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
147																					
148	**Telecom SCADA Protection and Control Sustainment**																				
149	Communication Upgrades	410	400	763	776	587	553	409	446	443	518	524	516	484	493	549	560	583	586	572	-
150	SCADA Systems Sustainment	707	733	784	811	843	795	785	855	848	992	1,004	989	927	944	1,053	1,073	1,117	1,123	1,096	1,262
151	Backbone Transport Technology Migration	-	-	410	6,652	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
152	Station Smart Device Upgrades	-	-	704	363	741	351	694	378	750	438	886	436	-	-	-	-	-	-	-	-
153	Telecommunications Ring Closure	-	-	-	-	-	286	3,979	-	-	-	-	-	-	-	-	-	-	-	-	-
154	**Total Telecom SCADA Protection and Control Sustainment**	**1,117**	**1,133**	**2,661**	**8,601**	**2,171**	**1,984**	**5,867**	**1,678**	**2,041**	**1,947**	**2,414**	**1,941**	**1,411**	**1,437**	**1,602**	**1,633**	**1,700**	**1,708**	**1,668**	**1,262**
155	**Total Telecom SCADA Protection and Control Projects**	**2,329**	**3,682**	**2,661**	**9,768**	**5,957**	**1,984**	**5,867**	**4,750**	**8,141**	**9,080**	**9,630**	**1,941**	**1,411**	**1,437**	**1,602**	**1,633**	**1,700**	**1,708**	**1,668**	**1,262**
156																					
157	**General Plant**																				
158	Kootenay Long Term Facilties Strategy	6,020	10,477	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
159	Okanagan Long Term Solution	69	75	3,984	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
160	Central Warehousing	1,755	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
161	Trail Building Purchase	-	10,000	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
162	Advanced Metering Infrastructure	4,501	27,931	6,099	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
163	Information Systems																				
164	Infrastructure Sustainment	1,111	1,118	1,207	1,244	1,355	1,302	1,299	1,380	1,388	1,566	1,593	1,574	1,525	1,555	1,666	1,727	1,789	1,810	1,788	2,004
165	Desktop Infrastructure Sustainment	1,115	1,122	1,239	1,277	1,321	1,269	1,267	1,346	1,353	1,527	1,553	1,534	1,487	1,516	1,625	1,684	1,744	1,765	1,743	1,954
166	Application Enhancements	1,235	1,242	1,296	1,336	1,382	1,328	1,325	1,408	1,415	1,598	1,625	1,605	1,555	1,586	1,700	1,762	1,825	1,847	1,824	2,044
167	Application Sustainment	1,179	1,210	1,276	1,341	1,441	1,463	1,559	1,932	2,082	2,350	2,549	2,518	2,592	2,644	2,999	3,109	3,399	3,440	3,576	4,008
168	PowerSense DSM Reporting Software	1,032	-	131	135	140	67	671	71	72	81	82	81	79	-	-	-	-	-	-	-
169	Vehicles	2,541	2,574	2,699	2,796	2,906	2,805	2,803	2,970	2,989	3,350	3,408	3,374	3,281	3,346	3,573	3,700	3,828	3,876	3,836	4,273
170	Metering Changes	403	406	212	222	234	229	233	252	259	298	308	621	613	637	695	735	775	800	805	919
171	Telecommunications	121	183	191	196	203	195	195	207	208	235	239	236	229	233	250	259	268	272	268	301
172	Buildings	1,362	883	601	278	287	629	273	247	534	313	368	337	351	302	520	401	698	413	887	1,002
173	Furniture and Fixtures	121	122	508	105	108	104	104	110	69	78	80	79	122	124	133	138	179	181	268	301
174	Tools and Equipment	528	457	477	491	508	488	487	518	520	587	597	590	572	583	625	648	671	679	670	-
175	**Total General Plant**	**23,093**	**57,800**	**19,920**	**9,423**	**9,885**	**9,881**	**10,217**	**10,442**	**10,889**	**11,984**	**12,403**	**12,548**	**12,405**	**12,527**	**13,786**	**14,164**	**15,175**	**15,082**	**15,665**	**16,806**
176																					
177	**Total Generation**	10,131	2,947	11,696	4,433	5,019	13,269	20,567	23,397	22,033	5,720	5,279	18,418	14,358	15,270	31,970	12,163	13,004	12,736	18,213	7,293
178	**Total Transmission&Stations**	35,254	32,854	32,024	38,385	30,220	61,195	76,936	34,056	39,510	13,125	15,197	21,812	49,617	45,622	21,647	33,826	20,866	37,161	67,393	12,751
179	**Total Distribution**	29,249	25,889	29,351	27,537	32,878	28,489	30,453	30,733	30,476	35,115	35,580	35,267	33,140	33,826	35,558	36,314	37,590	37,580	44,505	42,300
180	**Total Telecom**	2,329	3,682	2,661	9,768	5,957	1,984	5,867	4,750	8,141	9,080	9,630	1,941	1,411	1,437	1,602	1,633	1,700	1,708	1,668	1,262
181	**Total General Plant**	23,093	57,800	19,920	9,423	9,885	9,881	10,217	10,442	10,889	11,984	12,403	12,548	12,405	12,527	13,786	14,164	15,175	15,082	15,665	16,806
182	**Grand Total**	100,057	123,171	95,653	84,796	83,959	114,819	144,040	103,378	111,049	75,024	78,090	89,986	110,931	108,682	104,564	98,099	88,335	104,267	147,444	80,411

Appendix K

ISP Consultation Report

2012 Integrated System Plan

Public Consultation Report

FortisBC Inc.

Table of Contents

1. PUBLIC CONSULTATION PROCESS

FortisBC engaged in public consultation for the Integrated System Plan (ISP) to ensure that interested residents, government and business stakeholders were provided with an opportunity to learn about and provide input into the ISP. Activities included face to face meetings, four public open houses, six government meetings and two facilitated Super Groups (focus groups).

The activities included in the public consultation process encouraged customer groups including residential, general service (commercial), industrial, lighting, irrigation and wholesale to learn more about the ISP, to ask questions and to provide meaningful input. The process was advertised on the FortisBC website and in local news media across the FortisBC service territory. Stakeholders and First Nations were also notified individually by email. For the stakeholder list used and sample notifications, see Attachments 1 and 2 at the end of the report.

An overview of the process and the materials used for the public consultation activities for the ISP are provided in this report.

1.1 Consultation Notification

First Nations and stakeholders were notified of the ISP process and of the public open houses through email and in some cases by telephone. The stakeholder list endeavoured to represent all customer groups and included:

- First Nations (bands and nations);
- Local governments;
- Members of Parliament and Members of the Legislative Assembly;
- Area chambers of commerce and economic development organizations;
- FortisBC's large customers;
- Associations, builders and developers; and
- Participants in FortisBC's recent regulatory proceedings.

In addition, a news release was issued and newspaper advertisements were placed in print media throughout the service area. For the advertising booking sheet, advertisement and news release, see Attachments 3, 4 and 5. Notification and all consultation documents were also included on the FortisBC website (Attachment 6).

2. OPEN HOUSES

Four open houses were held in February 2011. They ran from 6:00 p.m. to 8:30 p.m., with scheduled time for a PowerPoint presentation (Attachment 7), an opportunity for open house participants to ask questions and then time for participants to visit information stations staffed by FortisBC representatives. Each station outlined information on one topic and provided graphic display panels (Attachment 8). Topics included general information (ISP and regulatory process), resource planning (planning margin and supply options), demand side management and advanced metering infrastructure, capital projects (proposed projects, customer priorities and environmental and social consideration fund), asset management and generation.

The first open house was held at the Holiday Inn Express in Kelowna on February 7, the second at the Osoyoos Seniors Centre in Osoyoos on February 8, the third was in Creston at the Creston and District Community Complex on February 9 and the final open house was at the Sandman Inn in Castlegar on February 10.

2.1 Open House Materials

Participants were provided with copies of the PowerPoint slides and display panels. Attendees were asked to fill out an exit questionnaire (Attachment 9) prior to their departure. The open house material, including a video recording of the presentation, provided at the open houses was displayed on the FortisBC website.

2.2 Subject Matter Experts for Open Houses

Attendees had an opportunity to ask questions and discuss the ISP with subject matter experts in the following areas:

- Customer service;
- Energy conservation;
- Resource planning and power supply;
- Generation;
- Transmission and distribution;
- Corporate services and information systems;
- Corporation and community relations; and

- Regulatory affairs.

2.3 Feedback received

A total of 54 people signed in to the four open houses and FortisBC received 39 exit surveys and four written responses as a result of the general ISP notification and open houses. A summary of the open house discussions is found in Attachment 10.

2.4 Follow-up Mechanisms

To ensure each attendee's input was included in the ISP, the final slide of each open house presentation included a number of feedback mechanisms. These were communicated verbally during the presentation and were also included in the open house notifications, PowerPoint presentation handouts and on the FortisBC website.

All open house participants who left contact information and those who provided contact information will be notified when the ISP is filed with the BC Utilities Commission.

3. SUPER GROUPS

In order to gather additional feedback and to ensure input from a representative sample of FortisBC customer groups, FortisBC hired Illumina Research Partners (formerly Environics Research Group) to conduct two Super Groups. The first was in Kelowna on February 23, 2011 and the second in Castlegar on February 24, 2011.

In each case a representative sample of customer groups (residential, general service, industrial, irrigation and lighting) was randomly selected. 70 participants were confirmed to attend, and told that they would be participating in a focus group. If potential participants asked, they were also told that the subject matter was long-range utility planning. Attendees received an honorarium for their participation. In Kelowna 56 people participated and in Castlegar 59 people participated.

Each participant was asked to fill out a short entrance survey. A PowerPoint presentation was provided by FortisBC staff, participants visited information stations staffed by FortisBC representatives and then participants completed a detailed exit survey.

3.1 Feedback received

FortisBC received 115 complete surveys with in-depth feedback. A summary of the feedback is presented in Illumina's report entitled *An Assessment of Public Reactions to the FortisBC ISP* in Attachment 12.

4. GOVERNMENT CONSULTATION

FortisBC sent invitations for the open houses with an offer to present to each of the local governments within the FortisBC service territory. Invitations were addressed to Mayor and Council, Regional Board Chair and Board, as well as the Chief Administrative or Executive Officers in each of the local governments. Five local governments including the City of Kelowna, City of Trail, District of Summerland, Town of Princeton and Regional District of Okanagan Similkameen requested and received presentations. Additionally, elected officials and representatives from local government attended the Kelowna, Osoyoos, Creston and Castlegar open houses.

Members of the Legislative Assembly and Members of Parliament from the FortisBC service area were invited to the open houses and offered presentations. FortisBC representatives met with the Member of the Legislative Assembly for West Kootenay Boundary. A list of meetings with government representatives is included in Attachment 11.

5. BUSINESS CONSULTATION

Invitations to the open houses were sent to wholesale and large customers as well as chambers of commerce, economic development commissions, associations and developers. Seven attendees to the open houses identified themselves as business customers.

6. CONSULTATION FINDINGS

6.1 Super Groups

The most comprehensive feedback was provided by the Super Groups which served to collect input from a representative sample of customer classes and to solicit more in-depth feedback from a greater number of individuals. In total 115 surveys were collected. A full reporting of results is included in the consultation materials at the end of this report in Attachment 12.

In summary:

- Overall Perceptions of ISP
    - 75 per cent strongly or somewhat agreed that the ISP fulfills the objective of planning for electrical needs over the next 20 to 30 years.
    - 94 per cent strongly or somewhat agreed that FortisBC's presentation helped them understand the ISP better.
    - 83 per cent strongly or somewhat agreed that FortisBC's presentation provided a balanced perspective on the ISP.
- Conservation / Demand Side Management
    - Almost three quarters of customers identified conserving energy /reducing energy consumption (73 per cent) and helping customers manage consumption (72 per cent) as critically important challenges for planning for future energy and infrastructure needs.
- Rates
    - Electrical rate increases are a concern across all potential ISP related initiatives. Kootenay participants are more price sensitive and consequently, they are less willing to accept rate increases for ISP initiatives.
- Resource Planning
    - 96 per cent of customers support the Planning Reserve Margin with 60 per cent willing to pay higher rates for the Planning Reserve Margin.
    - 75 per cent support the use of contractual agreements to fill small gaps in short term energy supply rather than building new generation resources.
- Social and Environmental Considerations
    - 89 per cent say social and environmental components such as visual screening, special environmental treatment or other community specific amenities should be considered when determining future capital project budgets. Only 50 per cent of these respondents are willing to pay higher rates for these components.
    - Over half of participants saw one per cent as a reasonable amount to add to the capital project budgets for social and environmental considerations.
- Asset Management

    - 92 per cent of respondents support the change from time-based to condition-based asset management.

- Advanced Metering Infrastructure
    - While significantly more customers selected having in-home displays provided as part of the AMI project, some hedged their selection with comments like only if there is no additional cost or if it does not increase electricity rates.
    - If in-home displays are optional, most customers would pay up to $50 for the technology.

6.2 Open house surveys and written submissions

Of the 54 people who signed in at the open houses, 39 provided open house exit surveys. FortisBC received an additional four written submissions as a result of the mail and email notifications and the open houses. The findings while more limited than the Super Group, are similar in character.

Within the ISP exit surveys:

- The majority of respondents strongly agreed or agreed that the open houses were useful, helped them understand the ISP better and provided a balanced perspective on the ISP. None disagreed.
- The majority of respondents agreed with FortisBC providing joint gas and electric energy efficiency programs. Five disagreed and one strongly disagreed.
- Respondents expressed an interest in future conservation and demand side management programs including LED lighting, energy audits for residential and commercial customers, promotion of and rebates for distributed generation / net metering, industrial power recovery programs, rebates for energy efficient appliances, time of use rates and district energy systems.
- The majority of respondents support the advanced metering infrastructure project and the use of a secure website for customers to monitor their energy use. There is mixed support for providing in-home displays and some respondents have concerns regarding EMF, cost versus benefit of program and loss of meter reader jobs.

- The majority of respondents strongly agree or agree with a shift from time-based to condition based asset management. One respondent disagrees and three respondents strongly disagree.
- The majority of respondents strongly agree or agree with including an additional budget item in capital projects for social and environmental considerations. Four respondents disagreed.
- The majority of respondents (17) think one per cent of a capital project budget is a reasonable amount to allocate to social and environmental considerations. A further 13 respondents think two per cent would be appropriate.

Of the four written submissions, one outlines the limited energy options available to Kaslo customers and requests consideration of time of use rates as a way to reduce personal electrical bills, two submissions express concern regarding advanced metering infrastructure (cost, electromagnetic fields, privacy) and the last correspondence requested clarification regarding projected rate increases over the next five years.

6.3 Presentations to local governments and MLA

While each government meeting had specific local questions, some general topics emerged:

- Concern regarding rate increases and impact on constituents;
- How FortisBC's investment in the utility is treated in rates;
- Net metering and clean energy generation;
- Support for demand side management measures;
- Support for advanced metering infrastructure with in-home displays but concerns regarding; electromagnetic field and loss of meter reading jobs;
- Support for time of use rates;
- Interest in customer growth calculations and levels of growth across FortisBC service area; and
- Concern regarding postage stamp rates and whether the Kootenay and Boundary regions pay for growth in the Okanagan area.

7. CONSULTATION MATERIAL

The following materials have been included as appendices:

- Attachment 1 - Stakeholder contact list
- Attachment 2 - Email notifications
- Attachment 3 - Advertisement booking dates
- Attachment 4 - ISP advertisement
- Attachment 5 - ISP news release
- Attachment 6 - FortisBC website screen shot
- Attachment 7 - Open house PowerPoint presentation
- Attachment 8 - Open house graphic information panels
- Attachment 9 - Open house exit survey
- Attachment 10 - Open house summaries
- Attachment 11 - Government Stakeholder meeting schedule
- Attachment 12 - Illumina Research Partners Super Group summary - *An Assessment of Public Reactions to the FortisBC ISP*

Attachment 1
STAKEHOLDER CONTACT LIST

First Nations

Method of Contact	Organization	Position
January 31, 2011 with offer to present and invitation to public open houses	Penticton Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Osoyoos Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Lower Kootenay Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Upper Similkameen Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Lower Similkameen Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Westbank First Nation	Chief
January 31, 2011 with offer to present and invitation to public open houses	Okanagan Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Upper Nicola Indian Band	Chief
January 31, 2011 with offer to present and invitation to public open houses	Shuswap Indian Band	Chief
2011 with invitation to public open houses and reminder of review process	Okanagan Nation Alliance	Grand Chief
2011 with invitation to public open houses and reminder of review process	Shuswap Nation Tribal Council	Chairman
2011 with invitation to public open houses and reminder of review process	Ktunaxa Nation	Tribal Chair
Email sent to Nation January 31, 2011 with offer to present and invitation to public open houses	Sinixt Nation	Appointed Spokesperson

Local Govenments

Method of Contact	Organization	Position
Email sent January 31, 2011	City of Castlegar	Mayor and Council
Email sent January 31, 2011	Town of Creston	Mayor and Council
Email sent January 31, 2011	Village of Fruitvale	Mayor and Council
Email sent January 31, 2011	City of Grand Forks	Mayor and Council
Email sent January 31, 2011	City of Greenwood	Mayor and Council
Email sent January 31, 2011	Village of Kaslo	Mayor and Council
Email sent January 31, 2011	City of Kelowna	Mayor and Council
Email sent January 31, 2011	Village of Keremeos	Mayor and Council
Email sent January 31, 2011	District of Lake Country	Mayor and Council

Method of Contact	Organization	Position
Email sent January 31, 2011	District of Lillooet	Mayor and Council
Email sent January 31, 2011	Village of Midway	Mayor and Council
Email sent January 31, 2011	Village of Montrose	Mayor and Council
Email sent January 31, 2011	City of Nelson	Mayor and Council
Email sent January 31, 2011	Town of Oliver	Mayor and Council
Email sent January 31, 2011	Town of Osoyoos	Mayor and Council
Email sent January 31, 2011	City of Penticton	Mayor and Council
Email sent January 31, 2011	Town of Princeton	Mayor and Council
Email sent January 31, 2011	City of Rossland	Mayor and Council
Email sent January 31, 2011	Village of Salmo	Mayor and Council
Email sent January 31, 2011	Village of Slocan	Mayor and Council
Email sent January 31, 2011	District of Summerland	Mayor and Council
Email sent January 31, 2011	City of Trail	Mayor and Council
Email sent January 31, 2011	Village of Warfield	Mayor and Council
Email sent January 31, 2011	Regional District of Central Kootenay	Chair
Email sent January 31, 2011	Regional District of Central Okanagan	Chair
Email sent January 31, 2011	Regional District of Kootenay-Boundary	Chair
Email sent January 31, 2011	Regional District of Okanagan-Similkameen	Chair

Members of Parliament and Members of the Legislative Assembly

Method of Contact	Riding	Position
Email sent January 31, 2011	Okanagan-Coquihalla	Member of Parliament
Email sent January 31, 2011	Kelowna-Lake Country	Member of Parliament
Email sent January 31, 2011	British Columbia Southern Interior	Member of Parliament
Email sent January 31, 2011	Kootenay Columbia	Member of Parliament
Email sent January 31, 2011	Penticton	Member of Legislative Assembly
Email sent January 31, 2011	Boundary-Similkameen	Member of Legislative Assembly
Email sent January 31, 2011	Kootenay West	Member of Legislative Assembly
Email sent January 31, 2011	Nelson-Creston	Member of Legislative Assembly
Email sent January 31, 2011	Westside-Kelowna	Member of Legislative Assembly
Email sent January 31, 2011	Kelowna-Lake Country	Member of Legislative Assembly
Email sent January 31, 2011	Kelowna-Mission	Member of Legislative Assembly
Email sent January 31, 2011	Fraser Nicola	Member of Legislative Assembly

Chambers of Commerce and Economic Development Organizations

Method of Contact	Organization	Position
Email sent January 31, 2011	Castlegar and District Chamber of Commerce	Executive Director
Email sent January 31, 2011	Creston and District Chamber of Commerce	Executive Director
Email sent January 31, 2011	Grand Forks Chamber of Commerce	Executive Director
Email sent January 31, 2011	Greenwood Board of Trade	Executive Director
Email sent January 31, 2011	Kaslo and Area Chamber of Commerce	Executive Director
Email sent January 31, 2011	Lake Country Chamber of Commerce	Executive Director
Email sent January 31, 2011	Nelson and District Chamber of Commerce	Executive Director

Method of Contact	Organization	Position
Email sent January 31, 2011	Penticton & Wine Country Chamber of Commerce	Executive Director
Email sent January 31, 2011	Rossland Chamber of Commerce	Executive Director
Email sent January 31, 2011	Summerland Chamber of Commerce	Executive Director
Email sent January 31, 2011	Trail and District Chamber of Commerce	Executive Director
Email sent January 31, 2011	Christina Lake Chamber of Commerce	Vice President
Email sent January 31, 2011	Kelowna Chamber of Commerce	Executive Director
Email sent January 31, 2011	Similkameen Country	Executive Director
Email sent January 31, 2011	Slocan District Chamber of Commerce	Executive Director
Email sent January 31, 2011	Central Okanagan Economic Development Commission	
Email sent January 31, 2011	Regional District of Kootenay Boundary	Community Economic Development Coordinator
Email sent January 31, 2011	Nelson Economic Development Partnership	General Manager of Community Futures
Email sent January 31, 2011	Osoyoos Indian Band	Osoyoos Indian Band

Large Customers		
Method of Contact	**Organization**	**Position**
Email sent January 31, 2011	UBC Okanagan	Assistant Vice President; Deputy Vice Chancellor
Email sent January 31, 2011	District of Lake Country	Director of Engineering
Email sent January 31, 2011	Al Stober Construction	Owner
Email sent January 31, 2011	City of Kelowna	Director
Email sent January 31, 2011	Interior Health Authority	Energy Manager
Email sent January 31, 2011	Big White Ski Resort	Vice President Operations, Vice President Real Estate and Development
Email sent January 31, 2011	Rona	Manager
Email sent January 31, 2011	Overwaitea Food Group	Energy Manager
Email sent January 31, 2011	Orchard Park Shopping Centre	General Manager, Operations Manager
Email sent January 31, 2011	Sysco	Vice President, Chief Financial Officer
Email sent January 31, 2011	Bingo Kelowna	Owner
Email sent January 31, 2011	McIntosh Properties	
Email sent January 31, 2011	Best Western Hotel	Owner
Email sent January 31, 2011	Callahan Construction	Owner
Email sent January 31, 2011	Uptown Rutland Business Association	President, Executive Director
Email sent January 31, 2011	Celgar	Managing Director of Operations, Energy Coordinator
Email sent January 31, 2011	Roxul	Factory Manager
Email sent January 31, 2011	Interfor	Plant Manager
Email sent January 31, 2011	Kalesnikoff	
Email sent January 31, 2011	Springer Creek	
Email sent January 31, 2011	Columbia Brewery	Director
Email sent January 31, 2011	Porcupine Wood Products	
Email sent January 31, 2011	ATCO Wood Products	
Email sent January 31, 2011	Wyndel Box and Lumber	
Email sent January 31, 2011	Selkirk College	
Email sent January 31, 2011	Regional District of Central Kootenay	
Email sent January 31, 2011	School District #20	

Method of Contact	Organization	Position
Email sent January 31, 2011	School District #8	
Email sent January 31, 2011	School District #51	
Email sent January 31, 2011	School District # 23	Director of Operations
Email sent January 31, 2011	School District #53	Manager of Operations
Email sent January 31, 2011	City of Trail	
Email sent January 31, 2011	City of Castlegar	
Email sent January 31, 2011	Regional District of Kootenay Boundary	
Email sent January 31, 2011	Town of Creston	
Email sent January 31, 2011	Red Mountain Resorts	
Email sent January 31, 2011	District of Summerland	Administrator
Email sent January 31, 2011	Town of Oliver	Director of Operations
Email sent January 31, 2011	Town of Osoyoos	Director of Public Works
Email sent January 31, 2011	Town of Princeton	
Email sent January 31, 2011	Regional District Okanagan Similkameen	
Email sent January 31, 2011	Weyerhaeuser Princeton	Mill Manager
Email sent January 31, 2011	Greenwood Forest Products	Manager
Email sent January 31, 2011	Princeton Wood Preserves	President
Email sent January 31, 2011	Agriculture Canada	Science Director
Email sent January 31, 2011	Okanagan-Kootenay Sterile Insect Release Program	
Email sent January 31, 2011	Okanagan Similkameen Cooperative Growers	General Manager
Email sent January 31, 2011	Vincor	Manager

Associations, Builders and Developers

Method of Contact	Organization	Position
Email sent January 31, 2011	Canadian Home Builders' Association Central Interior	President, Executive Officers
Email sent January 31, 2011	Canadian Home Builders' Association Central Okanagan	President, Executive Officers
Email sent January 31, 2011	Canadian Home Builders' Association Central Okanagan	President, Executive Officer
Email sent January 31, 2011	Canadian Home Builders' Association of BC	Chief Executive Officer
Email sent January 31, 2011	Fraser Basin Council	Sustainability Facilitator, BC Southern Interior
Email sent January 31, 2011	Urban Development Institute Kelowna	Chair, Executive Coordinator
Email sent January 31, 2011	BC and Yukon Hotel Association	Purchasing Program Coordinator
Email sent January 31, 2011	BC Apartment Owners and Managers Association	Chief Executive Officer
Email sent January 31, 2011	BC Chamber of Commerce	President and Chief Executive Officer, Vice President Policy Development
Email sent January 31, 2011	BC Greenhouse Growers Association	Executive Director
Email sent January 31, 2011	BC Restaurant & Foodservices Association	Membership Services Manager
Email sent January 31, 2011	Better Business Bureau of Mainland BC	President, Communications Specialist
Email sent January 31, 2011	Building Owners and Managers Association	Energy Conservation & Sustainability Programs
Email sent January 31, 2011	British Columbia Real Estate Association	
Email sent January 31, 2011	Building Owners and Managers Association	Executive Vice President
Email sent January 31, 2011	Business Council of British Columbia	President and Chief Executive Officer, Executive Vice President Policy
Email sent January 31, 2011	Community Energy Association	Manager, Community Outreach and Strategy

Method of Contact	Organization	Position
Email sent January 31, 2011	Council of Forest Industries	
Email sent January 31, 2011	Independent Power Producers of BC	Executive Director, Vice President Operations
Email sent January 31, 2011	Mining Association of BC	President & Chief Executive Officer
Email sent January 31, 2011	SolarBC	Executive Director, Residential Project Manager
Email sent January 31, 2011	Thermal Environmental Comfort Association	Manager
Email sent January 31, 2011	Urban Development Institute	Executive Director, Deputy Executive Director
Email sent January 31, 2011	Community Energy Association	Development and Partnership Manager
Email sent January 31, 2011	Rental Owners & Managers Association of BC	Chief Executive Officer
Email sent January 31, 2011	BC Health Services	
Email sent January 31, 2011	GeoTility Geothermal Installation Corp.	General Manager
Email sent January 31, 2011	Acorn Communities	President
Email sent January 31, 2011	Edgecombe Builders	President
Email sent January 31, 2011	Fenwick Developments	Chief Executive Officer
Email sent January 31, 2011	G Group of Companies	President
Email sent January 31, 2011		Site Supervisor
Email sent January 31, 2011	Rohit Communities	Regional Manager
Email sent January 31, 2011	Rykon Group	President
Email sent January 31, 2011	WestCorp Properties	Development Manager

Regulatory Participants

Method of Contact	Organization	Position
Email sent January 31, 2011	Nova Independent Resources Ltd.	President
Email sent January 31, 2011	Okanagan Environmental Industry Alliance	Executive Director
Email sent January 31, 2011	MGM Management	
Email sent January 31, 2011	Individual	
Email sent January 31, 2011	Horizon Technologies Inc.	
Email sent January 31, 2011	BC Sustainable Energy Association	
Email sent January 31, 2011	Individual	
Email sent January 31, 2011	BC Public Interest Advocacy Centre	
Email sent January 31, 2011	Commercial Energy Consumers Association of BC	
Email sent January 31, 2011	Joint Industry Electricity Steering Committee	Executive Director
By Telephone February 8, 2011	Individual	
Email sent January 31, 2011	Natural Resource Industries	
Email sent January 31, 2011	Individual	
Email sent January 31, 2011	Individual	
Email sent January 31, 2011	BC Ministry of Energy, Mines and Petroleum Resources	Director - Energy Efficiency
Email sent January 31, 2011	Mercer International	Vice President Strategic Initiatives
Email sent January 31, 2011	Big White Ski Resort	Managing Director
Email sent January 31, 2011	Town of Oliver	Chief Fincancial Officer
Email sent January 31, 2011	City of Rossland	City Manager
Email sent January 31, 2011	BC Hydro	Chief Regulatory Officer
Email sent January 31, 2011	Town of Osoyoos	
Email sent January 31, 2011	Town of Princeton	

Method of Contact	Organization	Position
Email sent January 31, 2011	ATCO Wood Products	
Email sent January 31, 2011	Weyerhaeuser	
Email sent January 31, 2011	Red Mountain Ventures	
Email sent January 31, 2011	Irrigation Ratepayers Group	
Email sent January 31, 2011	BC Municipal Electrical Utilities	City of Grand Forks
Email sent January 31, 2011	BC Municipal Electrical Utilities	City of Penticton
Email sent January 31, 2011	BC Municipal Electrical Utilities	City of Kelowna
Email sent January 31, 2011	BC Municipal Electrical Utilities	District of Summerland
Email sent January 31, 2011	BC Municipal Electrical Utilities	Nelson Hydro

Attachment 2
EMAIL NOTIFICATIONS

Sample Email Invitations

This version for regulatory participants, Chambers of Commerce, Economic Development Commissions, Associations, Builders and Developers and Large Customers

From: FBC Integrated System Plan
Sent: Monday, January 31, 2011 3:35 PM
Cc:
Subject: Open House Invite | FortisBC Integrated System Plan

FORTISBC

January 31, 2011

Good afternoon,

FortisBC is seeking public input as we develop an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs.

We will be hosting a series of public open houses throughout our service area during the week of February 7 – 11, 2011 and invite you to share your thoughts on the following topics:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or “smart meters”) and joint programs with Terasen Gas

Please visit any of the following open houses. Each open house will begin with a **presentation at 6 p.m.** and host information stations for more information and to answer your questions.

Kelowna: February 7, 2011 | 6:00 – 8:30 p.m.
Holiday Inn Express, 2429 Highway 97 N.

Osoyoos: February 8, 2011 | 6:00 – 8:30 p.m.
Osoyoos Senior Centre, 17 Park Place

Creston: February 9, 2011 | 6:00 – 8:30 p.m.
Creston and District Community Complex, 312 19th Ave.

Castlegar: February 10, 2011 | 6:00 – 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave.

If you are unable to attend an open house but would like to participate in the consultation process, you are encouraged to review the ISP information, including a video recording of the open house presentation, to be posted on the FortisBC website at www.fortisbc.com during the second week of February.

Feedback received on or before **February 25, 2011** will be considered, along with technical and financial information, as FortisBC prepares the Integrated System Plan for submission to the B.C. Utilities Commission in June 2011.

For more information or to return written comments, please contact Elvia Picco by phone at (250) 868-4517, by email at FBCisp@fortisbc.com or by mail, Attn: Integrated System Plan, Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7.

Sincerely,

Mark Warren
Director of Customer Service
FortisBC

Sample Invitation - Bands

From: Gibney, Bob
Sent: Monday, January 31, 2011 1:15 PM
To:
Subject: Open House Invite | FortisBC Integrated System Plan

January 31, 2011

Dear

FortisBC is seeking input as we develop an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs. We invite you and your council to share your thoughts on the ISP.

We would be happy to have a FortisBC representative provide an ISP presentation to you at one of your February or early March Council meetings. Alternately, you or a representative could attend a public open house or provide written feedback.

The ISP information, including a video recording of the open house presentation, will be posted on the FortisBC website at www.fortisbc.com during the second week of February should you wish to review the materials online. ISP information can also be provided to your office should you request it.

Specifically FortisBC is seeking input on the following topics:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or “smart meters”) and joint programs with Terasen Gas

Each open house will begin with a **presentation at 6 p.m**. FortisBC representatives will also be available at information stations to answer your individual questions.

Kelowna: February 7, 2011 | 6:00 – 8:30 p.m.
Holiday Inn Express, 2429 Highway 97 N.

Osoyoos: February 8, 2011 | 6:00 – 8:30 p.m.
Osoyoos Senior Centre, 17 Park Place

Creston: February 9, 2011 | 6:00 – 8:30 p.m.

Creston and District Community Complex, 312 19th Ave.

Castlegar: February 10, 2011 | 6:00 – 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave.

Feedback received on or before **February 25, 2011** will be considered, along with technical and financial information, as FortisBC prepares the Integrated System Plan draft for submission to the B.C. Utilities Commission in June 2011.

I have also contacted the Okanagan Nation Alliance to complete a review the Integrated System Plan when it becomes available in draft form in late February or early March, 2011.

For more information, to return written comments or to book a presentation, please contact me by:

- Phoning: 250-490-5141
- Emailing: bob.gibney@fortisbc.com
- Mailing: Attn: Bob Gibney, Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7.

Sincerely,

Bob Gibney
First Nations Executive Liaison
FortisBC

Sample Invitation - Nations

From: Gibney, Bob
Sent: Monday, January 31, 2011 1:18 PM
To:
Subject: Open House Invite | FortisBC Integrated System Plan

January 31, 2011

Dear

FortisBC is seeking input as we develop an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs. We invite you and your council to share your thoughts on the ISP.

We have already been in touch to coordinate a review of the draft ISP when it becomes available in late February or early March but also wanted to invite you to of a series of open houses we will be undertaking across the FortisBC service area during the week of February 7.

The ISP information, including a video recording of the open house presentation, will be posted on the FortisBC website at www.fortisbc.com during the second week of February should you wish to review the materials online. ISP information can also be provided to your office should you request it.

Specifically FortisBC is seeking input on the following topics:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or "smart meters") and joint programs with Terasen Gas

Each open house will begin with a **presentation at 6 p.m**. FortisBC representatives will also be available at information stations to answer your individual questions.

Kelowna: February 7, 2011 | 6:00 – 8:30 p.m.
Holiday Inn Express, 2429 Highway 97 N.

Osoyoos: February 8, 2011 | 6:00 – 8:30 p.m.
Osoyoos Senior Centre, 17 Park Place

Creston: February 9, 2011 | 6:00 – 8:30 p.m.

Creston and District Community Complex, 312 19th Ave.

Castlegar: February 10, 2011 | 6:00 – 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave.

Feedback received on or before **February 25, 2011** will be considered, along with technical and financial information, as FortisBC prepares the Integrated System Plan draft for submission to the B.C. Utilities Commission in June 2011.

For more information, to return written comments or to book a presentation, please contact me by:

- Phoning: 250-490-5141
- Emailing: bob.gibney@fortisbc.com
- Mailing: Attn: Bob Gibney, Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7.

Sincerely,

Bob Gibney
First Nations Executive Liaison
FortisBC

cc:

Sample Invitation – MLAs and MPs

From: Gibney, Bob
Sent: Monday, January 31, 2011 11:35 AM
To:
Subject: Open House Invite | FortisBC Integrated System Plan

January 31, 2011

Dear

As an elected official in the area, FortisBC would like to inform you that we will be holding a series of open houses this month to provide information and solicit input from interested parties on our Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs.

The open houses have been scheduled to provide the public and interested parties with an opportunity to comment on the principles of the Integrated System Plan and help us prepare the plan as we get ready to submit it to the B.C. Utilities Commission in June, 2011.

Specifically, FortisBC will be seeking public input on the following topics:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or “smart meters”) and joint programs with Terasen Gas

Feedback received on or before **February 25, 2011** will be considered, along with technical and financial information, as FortisBC prepares the Integrated System Plan for submission to the B.C. Utilities Commission.

The ISP information, including a video recording of the open house presentation, will be posted on the FortisBC website at www.fortisbc.com during the second week of February should you wish to review the materials online. In addition, I’d be pleased to provide an update on the status of the ISP at any time you may wish.

Please feel free to visit any of the following open houses. Each open house will begin with a **presentation at 6 p.m**. FortisBC representatives will also be available at information stations to answer your individual questions.

Kelowna: February 7, 2011 | 6:00 – 8:30 p.m.

Holiday Inn Express, 2429 Highway 97 N.

Osoyoos: February 8, 2011 | 6:00 – 8:30 p.m.
Osoyoos Senior Centre, 17 Park Place
Creston: February 9, 2011 | 6:00 – 8:30 p.m.
Creston and District Community Complex, 312 19th Ave.

Castlegar: February 10, 2011 | 6:00 – 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave.

For more information, to return written comments or if you would like to meet with me and a member of the Integrated System Plan team, please contact me by:

- Phoning: 250-490-5141
- Emailing: bob.gibney@fortisbc.com
- Mailing: Attn: Bob Gibney, Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7

Sincerely,

Bob Gibney
Corporate Services and Aboriginal Affairs Manager
FortisBC

Attachment 3
ADVERTISEMENT BOOKING DATES

Attachment 3 - ADVERTISEMENT BOOKING DATES

Outlet	City	Booking Dates (2011)
Castlegar News	Castlegar	Jan 27, Feb 3
Grand Forks Gazette	Grand Forks	Jan 28, Feb 4
Trail Daily Times and Weekender	Trail	Jan 28, Feb 4
Rossland News	Trail	Jan 27, Feb 3
Nelson Star	Nelson	Jan 28, Feb 4
Creston Valley Advance	Creston	Jan 27, Feb 3
Boundary Creek Times Mountaineer	Greenwood	Jan 26, Feb 2
Pennywise	Kaslo	Feb 1, Feb 8
Kelowna Capital News	Kelowna	Jan 28, Feb 4
Kelowna Daily Courier	Kelowna	Jan 29, Feb 5
The Review in Keremeos and OK Falls	Keremeos	Jan 27, Feb 3
Oliver Chronicle	Oliver	Jan 26, Feb 2
Osoyoos Times	Osoyoos	Jan 26, Feb 2
Penticton Herald/Okan. Sat.	Penticton	Jan 29, Feb 5
Similkameen News Leader	Princeton	Jan 24, Jan 31
Similkameen Spotlight	Princeton	Jan 31
Summerland Review	Summerland	Jan 27, Feb 3

Attachment 4
ISP ADVERTISEMENT

Public open house

Integrated System Plan

Your views are important to us

FortisBC is seeking public input as we develop an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs.

We invite you to share your thoughts on these topics:
- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or "smart meters") and joint programs with Terasen Gas

Please visit any of the following open houses. Each open house will **begin with a presentation at 6 p.m.** FortisBC representatives will also be available at information stations to answer your individual questions.

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Creston and District Community Complex, 312 19th Ave

Castlegar: February 10, 2011 | 6:00 – 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave

If you can't attend one of the one houses but would like to participate, you are encouraged to review the ISP information, including a video recording of the open house presentation, to be posted on the FortisBC website. Written feedback/comments, should be addressed to FortisBC at Suite 100, 1975 Springfield Road, Kelowna BC V1Y 7V7, Attn: Integrated System Plan.

Feedback received on or before February 25, 2011 will be considered, along with technical and financial information, as FortisBC prepares the Integrated System Plan for submission to the BC Utilities Commission in June 2011.

For more information, call 1-866-4FORTIS (1-866-436-7847) or visit www.fortisbc.com

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Energizing your community.

FORTISBC

www.fortisbc.com

Attachment 5
ISP NEWS RELEASE

FORTISBC

News Release

Open house public consultation sessions scheduled to help FortisBC develop Integrated System Plan

Kelowna, BC – **February 2, 2011:** FortisBC will be holding a series of open houses next week to seek public input as the utility develops an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needed to meet customers' long term energy needs – then set out a five-year business plan to meet these needs.

"FortisBC is committed to open dialogue with our customers. The public feedback we receive will help to shape the Integrated System Plan as we prepare to file it with the British Columbia Utilities Commission later this year," said Doyle Sam, Vice President, Engineering and Operations at FortisBC. "The comments and opinions we receive will guide us in planning infrastructure and energy efficiency programs our customers will value."

FortisBC is asking for public input on its capital project requirements, future resource planning, as well as energy efficiency and conservation measures, which include:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations.
- Future resources – planning for electrical generation.
- Energy efficiency and conservation measures – advanced metering infrastructure (or "smart meters") and joint programs with Terasen Gas.

Interested individuals are invited to drop by any of the open houses where project information panels will be on display and a presentation is scheduled for 6 p.m. in each location.

Kelowna
Monday, February 7, 2011 | 6- 8:30 p.m.
Holiday Inn Express, 2429 Hwy. 97 N

Osoyoos
Tuesday, February 8, 2011| 6 - 8:30 p.m.
Osoyoos Senior Centre, 17 Park Place

Creston
Wednesday, February 9, 2011 | 6 - 8:30 p.m.

Creston and District Community Complex, 312 19 Ave.

Castlegar
Thursday, February 10, 2011 | 6 - 8:30 p.m.
Sandman Hotel, 1944 Columbia Ave.

All feedback received from customers, stakeholders and First Nations will be considered, along with technical and financial information, as FortisBC prepares its Integrated System Plan submission for the BCUC. Once the ISP has been filed, the BCUC will establish a schedule for the regulatory review process.

For more information about the ISP and the open houses visit www.fortisbc.com or call 1-866-4FORTIS (1-866-436-7847). Individuals who are unable to attend the open houses, but who would like to provide input, are encouraged to review the ISP information posted on the FortisBC website at www.fortisbc.com and submit written feedback/comments by February 25, 2011. Written submissions should be addressed to FortisBC at Suite 100, 1975 Springfield Road, Kelowna, BC, V1Y 7V7 Attn: Integrated System Plan.

About FortisBC
FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves approximately 161,000 customers directly and indirectly through wholesale utilities in the southern interior of B.C. FortisBC owns and operates four regulated hydroelectric generating plants and approximately 7,000 kilometres of transmission and distribution power lines. FortisBC employs over 500 people in British Columbia and is an indirect wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada. Fortis Inc. shares are listed on the Toronto Stock Exchange and trade under the symbol FTS. Additional information can be accessed at www.fortisinc.com or www.sedar.com.

-30-

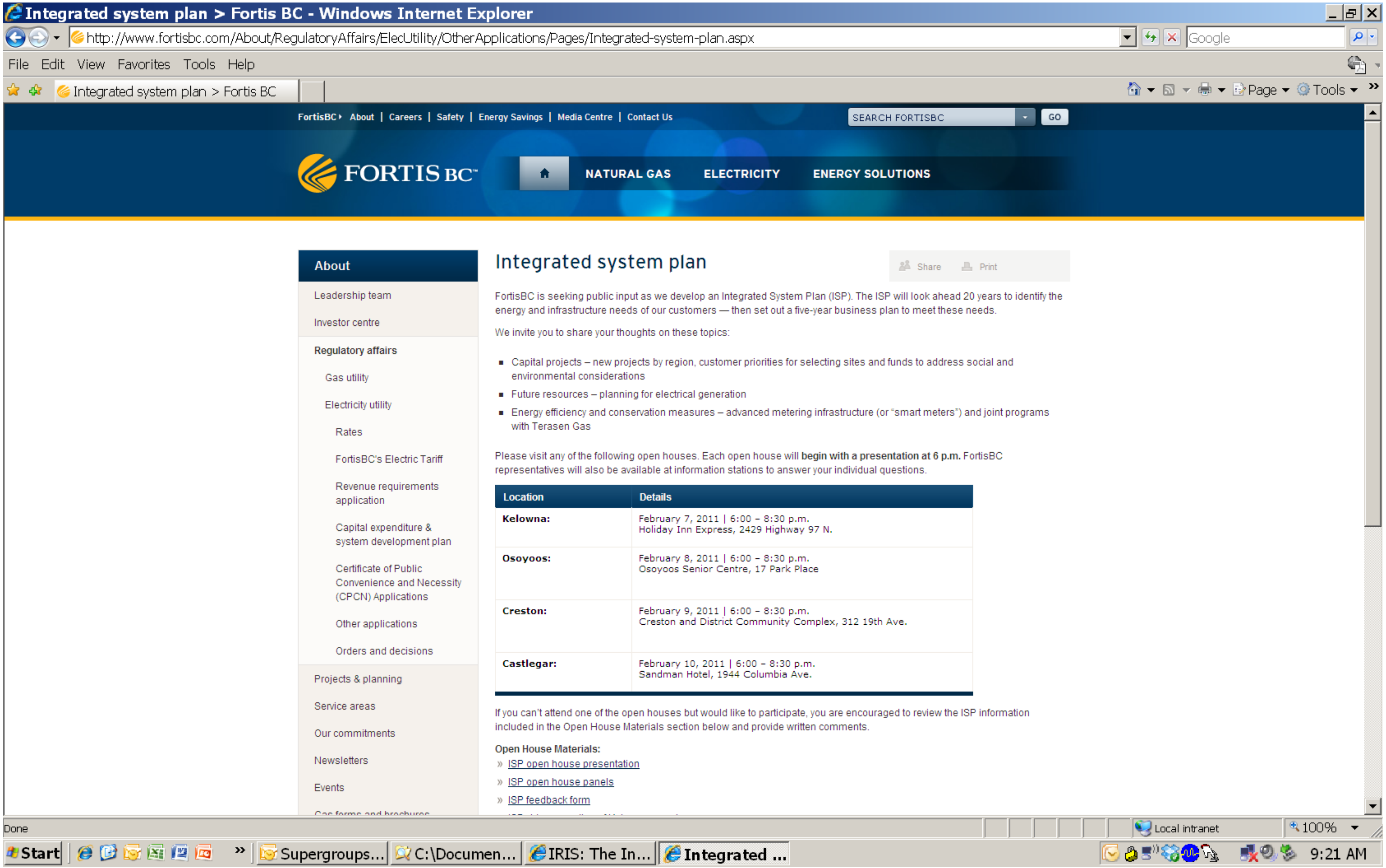
For further information contact:
Neal Pobran
Corporate Communications Manager
Tel: (250) 469-8128
Cell: (250) 718-8986
www.fortisbc.com

Attachment 6

FORTISBC WEBSITE SCREEN SHOT

Attachment 6 - FORTISBC WEBSITE SCREEN SHOT

Screen shot of FortisBC webpage found at
http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/OtherApplications/Pages/Integrated-system-plan.aspx



Integrated system plan > Fortis BC - Windows Internet Explorer

FortisBC › About | Careers | Safety | Energy Savings | Media Centre | Contact Us

NATURAL GAS   ELECTRICITY   ENERGY SOLUTIONS

About
- Leadership team
- Investor centre
- Regulatory affairs
  - Gas utility
  - Electricity utility
    - Rates
    - FortisBC's Electric Tariff
    - Revenue requirements application
    - Capital expenditure & system development plan
    - Certificate of Public Convenience and Necessity (CPCN) Applications
    - Other applications
    - Orders and decisions
- Projects & planning
- Service areas
- Our commitments
- Newsletters
- Events

Integrated system plan

FortisBC is seeking public input as we develop an Integrated System Plan (ISP). The ISP will look ahead 20 years to identify the energy and infrastructure needs of our customers — then set out a five-year business plan to meet these needs.

We invite you to share your thoughts on these topics:

- Capital projects – new projects by region, customer priorities for selecting sites and funds to address social and environmental considerations
- Future resources – planning for electrical generation
- Energy efficiency and conservation measures – advanced metering infrastructure (or "smart meters") and joint programs with Terasen Gas

Please visit any of the following open houses. Each open house will **begin with a presentation at 6 p.m.** FortisBC representatives will also be available at information stations to answer your individual questions.

Location	Details
Kelowna:	February 7, 2011 | 6:00 – 8:30 p.m. Holiday Inn Express, 2429 Highway 97 N.
Osoyoos:	February 8, 2011 | 6:00 – 8:30 p.m. Osoyoos Senior Centre, 17 Park Place
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Castlegar:	February 10, 2011 | 6:00 – 8:30 p.m. Sandman Hotel, 1944 Columbia Ave.

If you can't attend one of the open houses but would like to participate, you are encouraged to review the ISP information included in the Open House Materials section below and provide written comments.

Open House Materials:
- ISP open house presentation
- ISP open house panels
- ISP feedback form

Attachment 6 - FORTISBC WEBSITE SCREEN SHOT

Integrated system plan > Fortis BC - Windows Internet Explorer

http://www.fortisbc.com/About/RegulatoryAffairs/ElecUtility/OtherApplications/Pages/Integrated-system-plan.aspx

- Revenue requirements application
- Capital expenditure & system development plan
- Certificate of Public Convenience and Necessity (CPCN) Applications
- Other applications
- Orders and decisions
- Projects & planning
- Service areas
- Our commitments
- Newsletters
- Events
- Gas forms and brochures

Location	Details
Kelowna:	February 7, 2011 | 6:00 – 8:30 p.m. Holiday Inn Express, 2429 Highway 97 N.
Osoyoos:	February 8, 2011 | 6:00 – 8:30 p.m. Osoyoos Senior Centre, 17 Park Place
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If you can't attend one of the open houses but would like to participate, you are encouraged to review the ISP information included in the Open House Materials section below and provide written comments.

Open House Materials:

» ISP open house presentation
» ISP open house panels
» ISP feedback form
» ISP video recording of Kelowna open house

Provide us with your comments:

Feedback / comments returned at the open houses or in writing on or before **Friday, February 25, 2011** will be considered, along with other technical and financial information as FortisBC prepares the Integrated System Plan for submission to the BC Utilities Commission.

To return your feedback / comments:

Emailing: FBCisp@fortisbc.com

Mail: Integrated System Plan
Suite 100 – 1975, Springfield Road
Kelowna, BC, V1Y 7V7

Faxing: (250) 717-0801

For more information, call **1-866-436-7847** or email FBCisp@fortisbc.com

Fortis › About › ... › Electricity utility › Other applications › Integrated system plan

The future. We've got our best people on it.

FORTIS BC

Attachment 7
OPEN HOUSE POWERPOINT PRESENTATION

FortisBC Integrated System Plan

Public Open House - February 2011

Mark Warren

FortisBC

Director of Customer Service

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FORTISBC

Tonight

FortisBC ISP overview **6:00 – 6:30**
- High level goals and principles

Q&A at information stations **6:45 – 8:00**
- Visit each station
- Get detailed answers to your questions
- Fill out forms and provide your input

3 FORTISBC

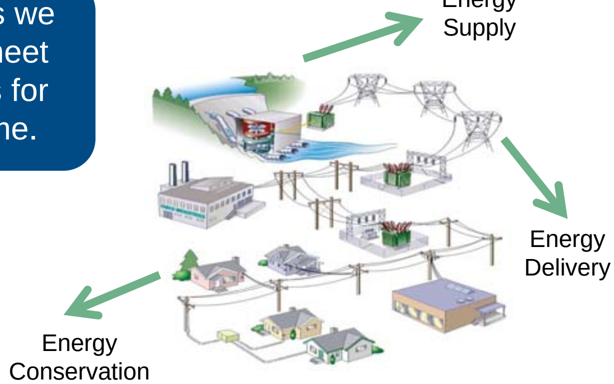
FortisBC
Providing electricity to southern interior for 100+ years

- A regulated utility based in Kelowna, BC, established in 1897
- Serves approximately 161,000 customers
- Owns and operates four generating plants
- Employs over 500 people
- Wholly owned subsidiary of Fortis Inc.

4 FORTISBC

The ISP:
A balanced framework for the future

The ISP ensures we will be able to meet customer needs for decades to come.



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FORTISBC

The FortisBC ISP:
A balanced framework for the future

1. The challenge: planning today to meet customer needs for decades to come.

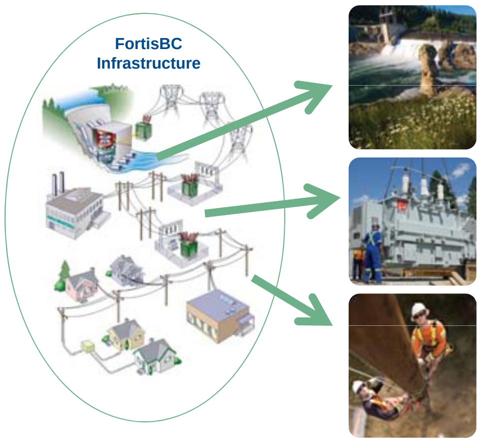
We must consider how we:

- Maintain existing infrastructure
- Meet growing demand for reliable electricity
- Meet dynamic public policy requirements
- Manage bill impacts
- Hear and act on customer input and priorities

6

FORTISBC

1. Planning today for the future
…so we can maintain our existing infrastructure



Generation station 100 plus year life

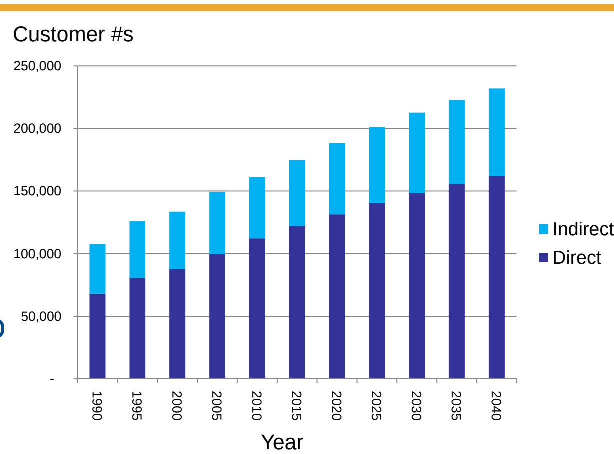
Transformer 40-60 year life

Wooden pole 40-70 year life

7 FORTISBC

2. Planning today for the future
…So we can meet growing demand from customers

Customer growth…



…is expected to continue in coming years

8 FORTISBC

3. Planning today for the future
…So we can meet dynamic public policy requirements

Greenhouse gases

Electric vehicles

Smart grid

Conservation

Aesthetics

Renewable generation

Environment al Legislation

9

FORTISBC

4. Planning today for the future
…So we can manage bill impacts

We know that every investment must be prudent...

...because it will impact the bill.

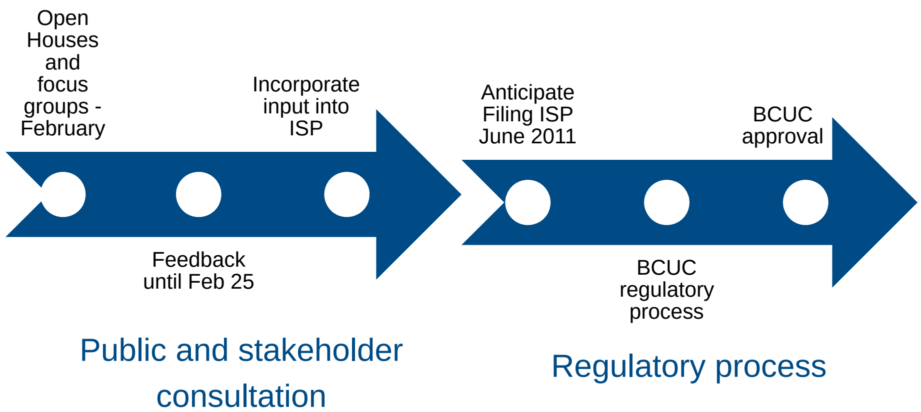
	Approx.
5km of transmission line	= 0.1% rate impact
New substation	= 0.5% rate impact
50 MW generation plant	= 2.5% rate impact

So before we build we consider the impact to your bill

10

FORTISBC

5. Planning today for the future
…So we seek out your input and priorities



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FORTISBC

The FortisBC ISP:
A balanced framework for the future

1. The challenge: planning today to meet your needs for decades to come

2. The response: the ISP is a balanced framework for:

   - Addressing growth
   - Ensuring prudent and sustainable system maintenance
   - Improving customer service levels
   - Flexibility to meet dynamic public policy requirements

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1. The ISP is a balanced framework... **For addressing growth**

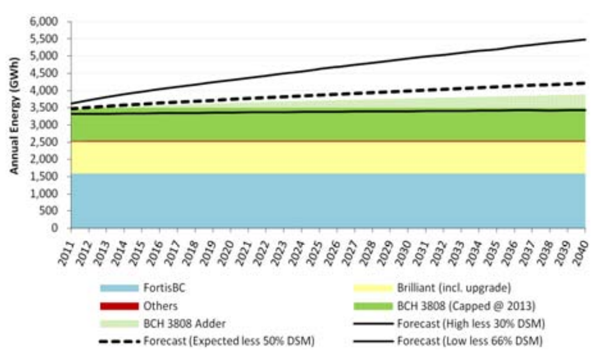
- Begin by predicting load growth over next 20 years
- Assessing existing capability to meet demand
- Identifying potential solutions to meet need in time

13 FORTISBC

2. The ISP is a balanced framework... **For addressing growth**

We began by forecasting load growth over the next 20 years – and our ability to meet

Big picture: We have forecast overall growth in load ...

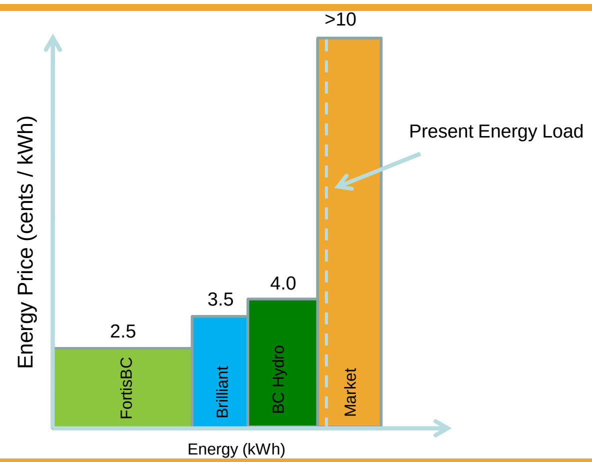


…and found we will need more energy to meet growth

14 FORTISBC

3. The ISP is a balanced framework... **For addressing growth**

New power supply costs significantly more than existing power supply



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FORTISBC

4. The ISP is a balanced framework... **For addressing growth**

We began by forecasting load growth over the next 20 years – and our ability to meet it

Local picture:
We looked at specific communities and customers...

...and found that we will need new investments to serve them.

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FORTISBC

5. The ISP is a balanced framework... **For addressing growth**

- Big Picture:
  - Power purchase from the Waneta expansion will reduce need for new generation infrastructure
  - Determined that we need to have supply insurance (planning reserve margin)
  - Committed to continued expansion of our conservation programs (e.g. PowerSense)
- Local Picture:
  - Increase capacity at existing locations through station upgrades
  - Increase capacity with new station south of Penticton

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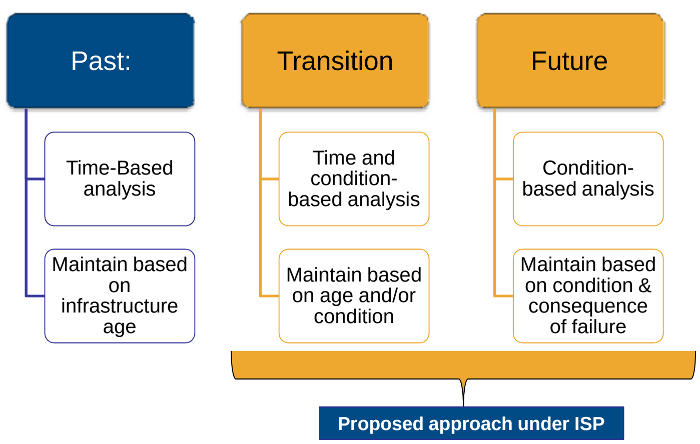
FORTISBC

6. The ISP is a balanced framework... **For ensuring our system serves customers for years**



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FORTISBC

7. The ISP is a balanced framework... **For improving service levels**

Advanced Metering Infrastructure

- Providing customers with better information about their energy usage
- Helping customers manage their energy use

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FORTISBC

8. The ISP is a balanced framework... **For improving service levels**

By helping customers use information to manage their energy use

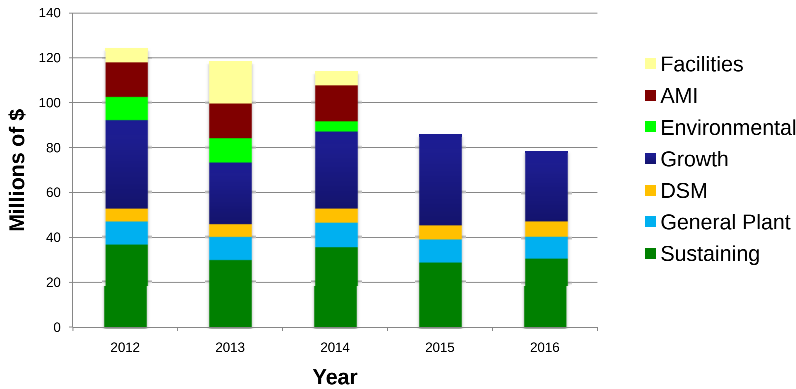
No cost → Higher cost

Spectrum of PowerSense programs help customers reduce use

20

FORTISBC

The ISP is a balanced framework for the future
Forecast capital expenditures



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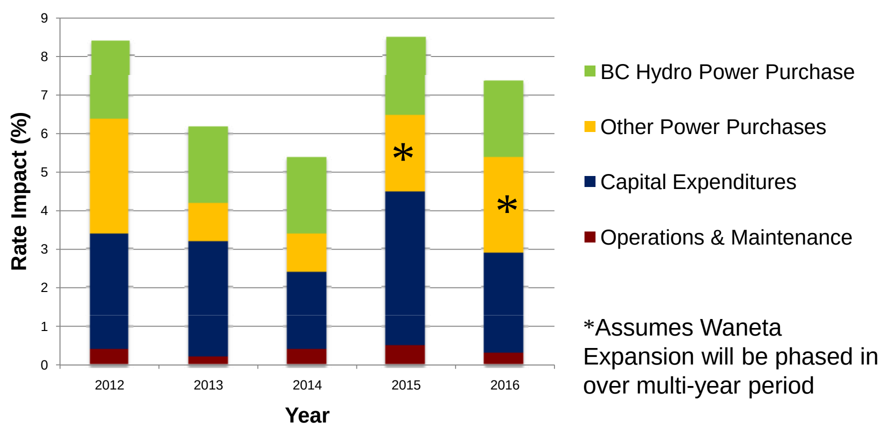
FORTISBC

The ISP is a balanced framework for the future
Estimated rate increases



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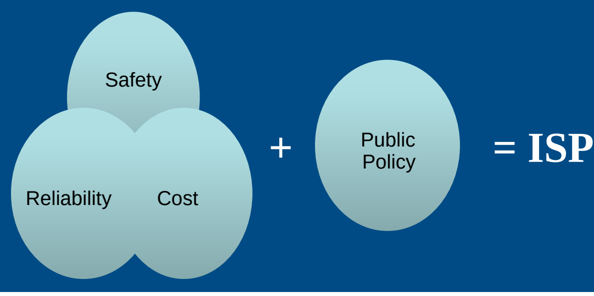
FORTISBC

The FortisBC ISP:
A balanced framework for the future

1. The challenge: planning today to meet your needs for decades to come
2. The Response: the ISP is a balanced framework



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FORTISBC

We want to hear from you!

We Want To Hear Your Thoughts On:	Booth
- How we can make sure you are heard during this process	Overview - ISP - Regulatory Process
- Appropriate spending on aesthetic mitigation - Your priorities around site location	Growth - Resource Planning - Capital
-Our infrastructure management approach (condition vs. time-based)	Sustainment - Generation - Infrastructure management - Support services (IT/fleet/etc)
- Whether FortisBC should fund in-house displays - If there are future programs or rebates you want to see	Improving Service - Metering - DSM

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FORTISBC

Your views are important

- ***Give us your feedback form before you leave!***
- Contact us at:
  - Website: www.fortisbc.com or www.bcuc.com
  - E-mail: FBCisp@fortisbc.com
  - Phone:1-866-4 FORTIS (1-866-436-7847)
  - Mail: Attn: Integrated System Plan, Suite 100 – 1975 Springfield Road, Kelowna, BC, V1Y 7V7

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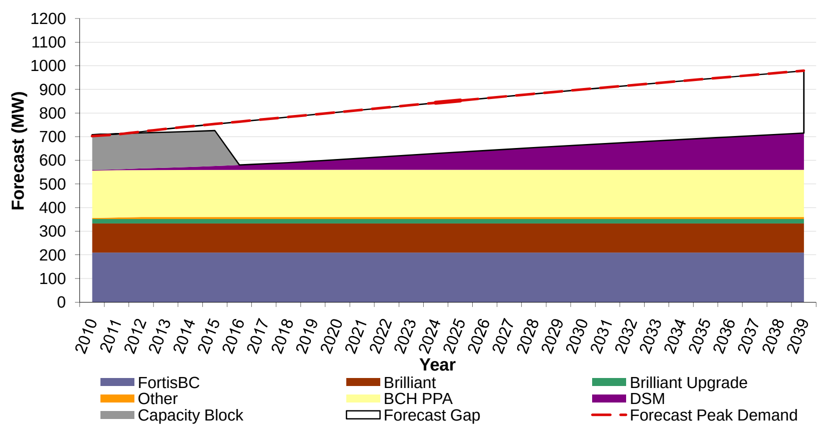
The ISP is a balanced framework for the future
FortisBC capacity resource stack – before Waneta Expansion



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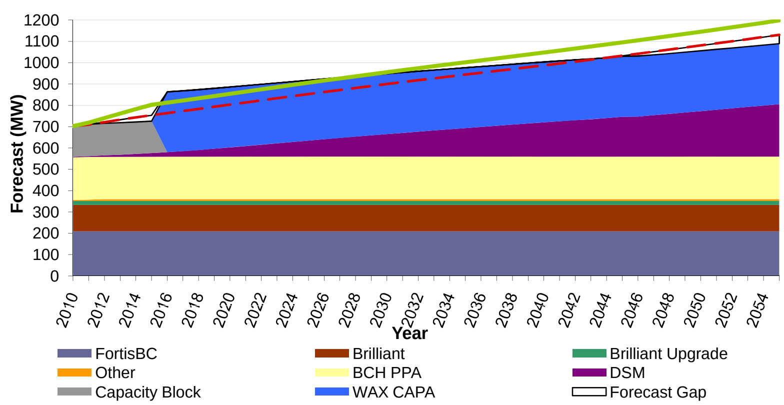
FORTISBC

The ISP is a balanced framework for the future
FortisBC capacity resource stack – with Waneta Expansion



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FORTISBC

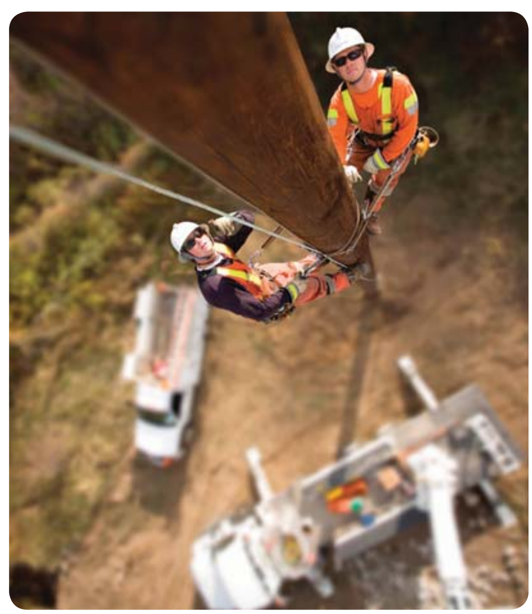
Attachment 8
OPEN HOUSE GRAPHIC INFORMATION PANELS

Welcome to our open house

Thanks for coming

Please sign in and help yourself to refreshments

Integrated System Plan (ISP)



Looks ahead 20 years to identify the energy and infrastructure needs of our customers — then sets out a five-year business plan to meet these needs.

- Identifies what projects are needed to meet future growth and sustain existing infrastructure
- Outlines energy efficiency and conservation measures
- Your input is important

Anticipated ISP timeline

Consultation

JAN | FEB (1) | MAR (2) | APR | MAY (3)

1. Public input deadline February 25
2. Public, stakeholder and First Nations Consultation February – March 2011
3. Finalize ISP May 2011

Regulatory process

JUN (4) | JUL | AUG | SEP (5) | OCT (6) →

4. File ISP with BCUC June 2011
5. BCUC review process Fall 2011
6. BCUC decision late 2011

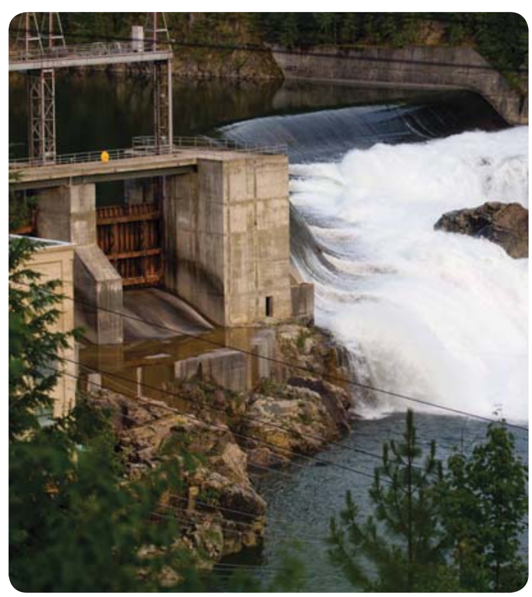
Planning for future power supply

2011 Resource Plan:

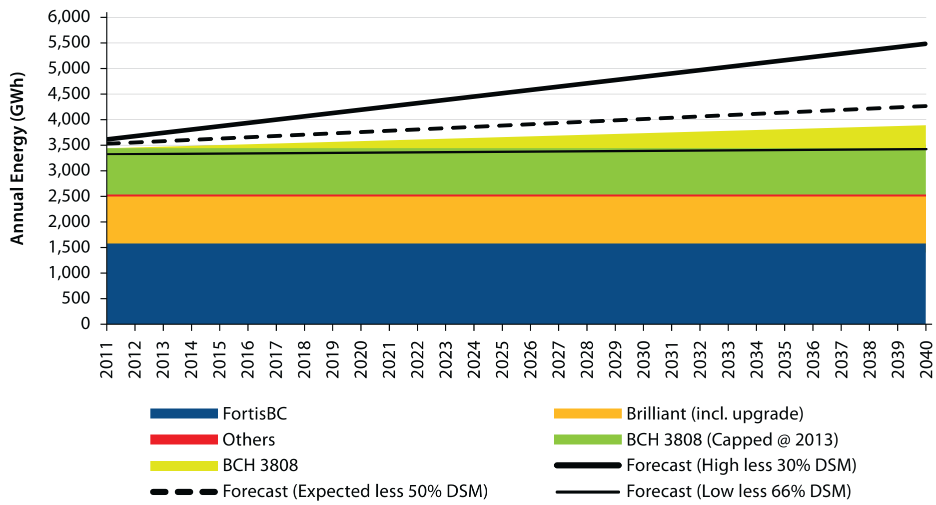
- Looks at the next 30 years to identify shortfalls and investigate future options
- Planning now is critical for the future – new generation can take decades to plan and acquire

Resource Plan goals:

- Ensure long-term reliable power for customers through acquisition of sufficient firm resources
- Reduce uncertainty and risks in current strategy which includes purchases power from the market
- Balance cost effectiveness with the directions and policy actions of the Clean Energy Act



Annual energy resource / Load gap (GWh)

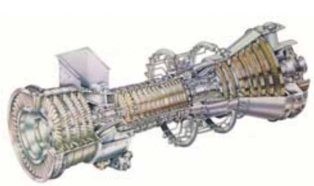


Energizing your community

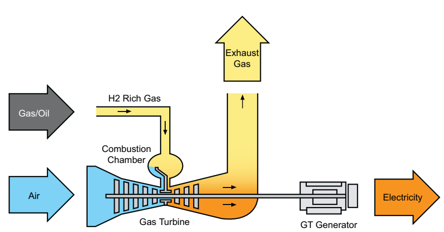
www.fortisbc.com

Power supply resources examples

Simple cycle gas turbine

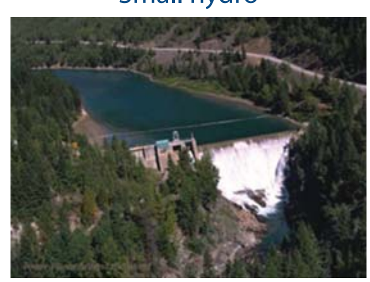


Turbine



Simple cycle gas turbine schematic

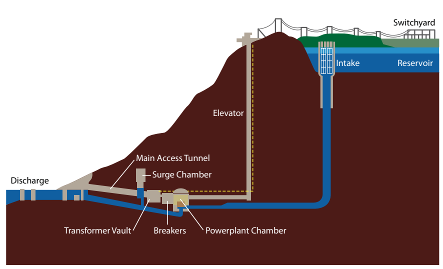
Small hydro



BC Hydro's Aberfeldie

Pumped storage hydro

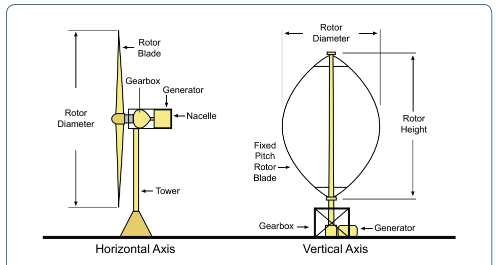
Senaca, PA



Power supply resources examples

Wind

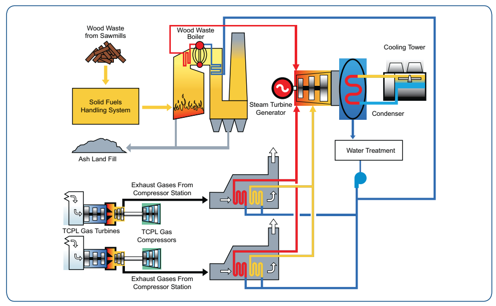
Wind farm near Pincher Creek Alberta



Wind turbine configurations

Biogas

Co-generation facility in Kimberley



Planning reserve margin (PRM)

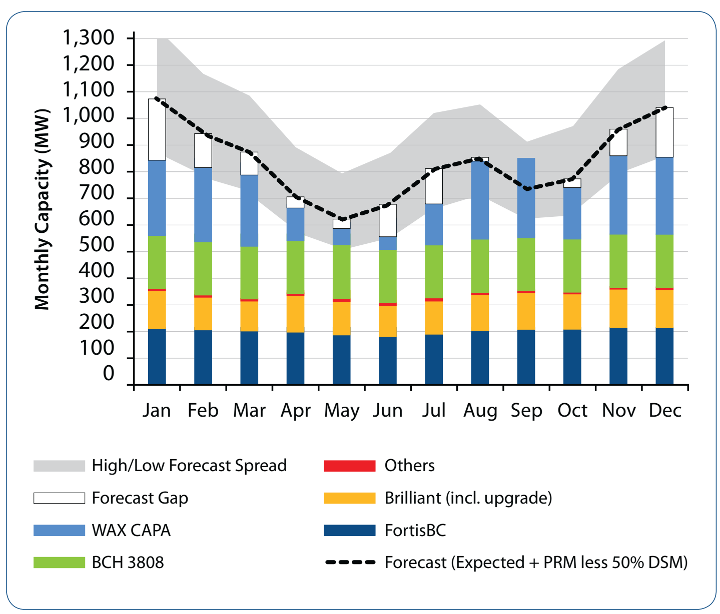
A planning reserve margin is:

- The power supply insurance that allows a utility to reliably serve customers

Three primary drivers for PRM:

- Unavailability of supply due to unplanned generating unit or transmission outages
- Unexpectedly high loads, typically due to extended extreme weather events
- A period of load growth that outpaces the possible installation of new power supply resources

2040 monthly capacity with expected load



Capital projects

Sustaining capital:

- Shift from a period of capital investment in new infrastructure to period of sustaining capital
- Shift from greenfield construction to brownfield construction
- Focus on continuing reliability through maintaining and upgrading current infrastructure
- Current projects and programs create a balance between rates and reliability
- Continue to provide safe and reliable service at the lowest reasonable costs

Proposed Kootenay and Boundary region projects

Station Improvements:

- Beaver Park substation (Trail)
  - Upgrade and expand existing Beaver Park substation to accommodate larger transformer
  - Convert transmission system in Montrose and Fruitvale to 25kV
  - Remove and salvage Fruitvale and Hearns substations
  - Project solves capacity issues, removes two stations, removes old equipment

- Grand Forks terminal station
  - Upgrade station by adding terminal transformer
  - Remove and salvage transmission lines (9 and 10 Lines) between Christina Lake and Rossland
  - Adding station offsets costs otherwise required to maintain 9 and 10 Lines
  - Provides continued reliability for area customers

Proposed Okanagan region projects

Station improvements:

- DG Bell terminal station (Kelowna)
  - Addition of Static VAR Compensator (SVC) which will support the voltage of Kelowna's transmission system needed by 2015 – 2017
- Lee terminal station (Kelowna)
  - Addition of a third terminal transformer to maintain reliable service to the Kelowna area as the load continues to grow – needed by 2015
  - Addition of distribution transformer possibly needed by 2018

Transmission improvements:

- Ellison to Sexsmith Road transmission
  - New 138kV transmission line from Ellison substation along Highway 97 to link with existing line at the corner of Highway 97 and Sexsmith Road
  - Completes transmission loop for customers in north Kelowna including airport and University of BC Okanagan
  - Significantly improves reliability in the area

Energizing your community

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Customer priorities

FortisBC must always balance safety, reliability and cost when undertaking new projects, as well as other considerations important to customers and communities.

These may include:

- Proximity to other buildings and amenities (homes, schools, parks etc.)
- Environmental considerations (natural habitat, wildlife, "no net loss")
- Aesthetics
- Effects during construction
- Risk of project delay
- Flexibility for future growth

Please share your priorities with us.

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Social and environmental consideration fund

Every project in every community is a little bit different.

- Our customers are telling us they want additional project components
- Projects may need:
  - Additional visual screening (vegetation, berming or fencing)
  - Special environmental treatment
  - Other community specific amenities

Would you consider adding project funds for social and environmental considerations? If so, how much is reasonable? 1-3 per cent of project total ($1000 - $3000 for every $100,000)?

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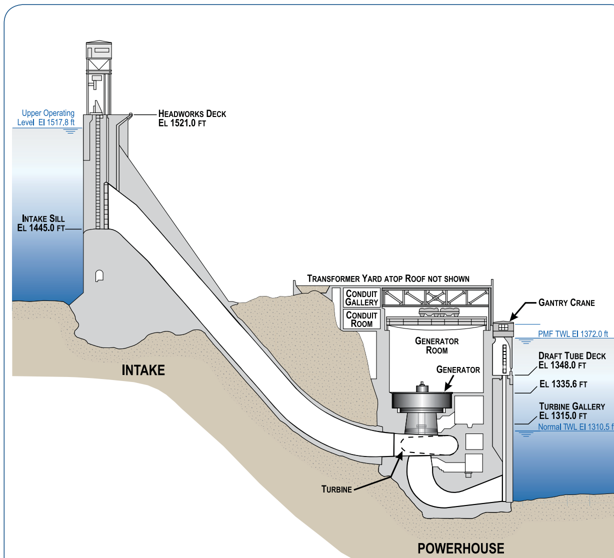
FortisBC generation

Power generation:

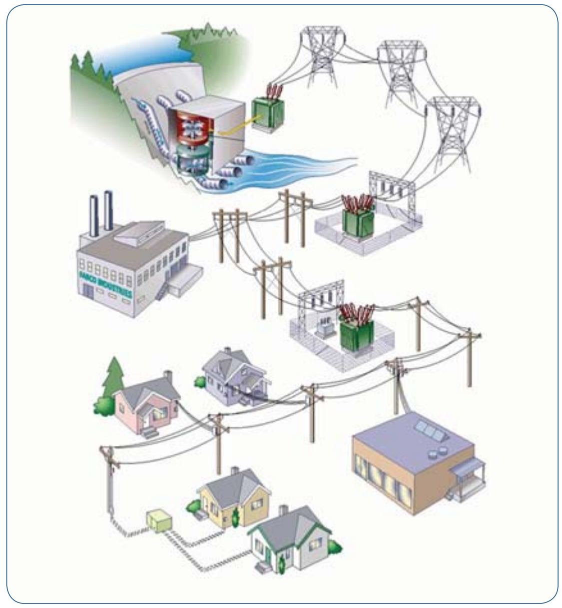
- Water flows from the reservoir, down the penstock and then spins a turbine connected to a generator
- The generator converts mechanical energy into electrical energy

Future generation projects:

- Moving from period of mechanical and electrical unit upgrades to upgrading the infrastructure required to support generation – like dams, power house structures, spill gates and spill ways
- Work is scheduled based on engineering and condition assessments



FortisBC infrastructure



FortisBC manages over $1.2 billion in infrastructure including:

- Four generating plants on Kootenay River
- 7,000 km of transmission and distribution lines
- 80 substations (including 13 for third parties)
- 102,000 poles
- 346 fleet vehicles
- 14 office buildings
- Over 670 desktop and laptop computers and 74 servers and storage devices

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Managing infrastructure

With over $1.2 billion of infrastructure in the FortisBC system, prudent management of infrastructure is essential.

- Proposes shift from time-based management to condition-based management
- Once new system is in place, this approach ensures maintenance dollars will be used more effectively
  - Critical and high risk equipment monitored and dealt with first

Energizing your community

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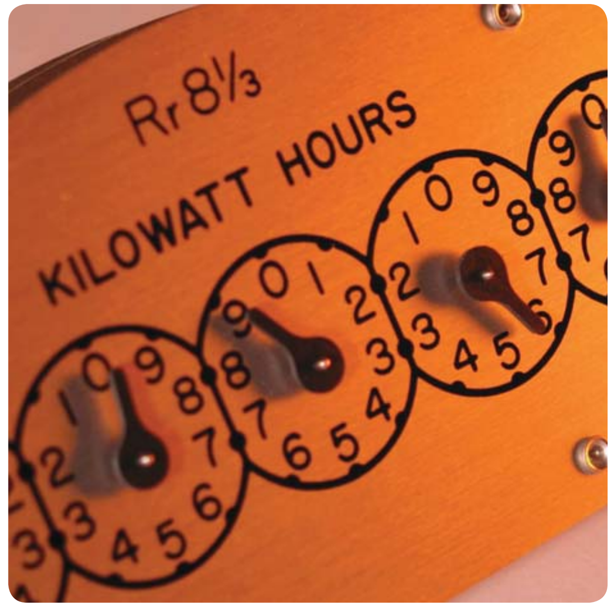
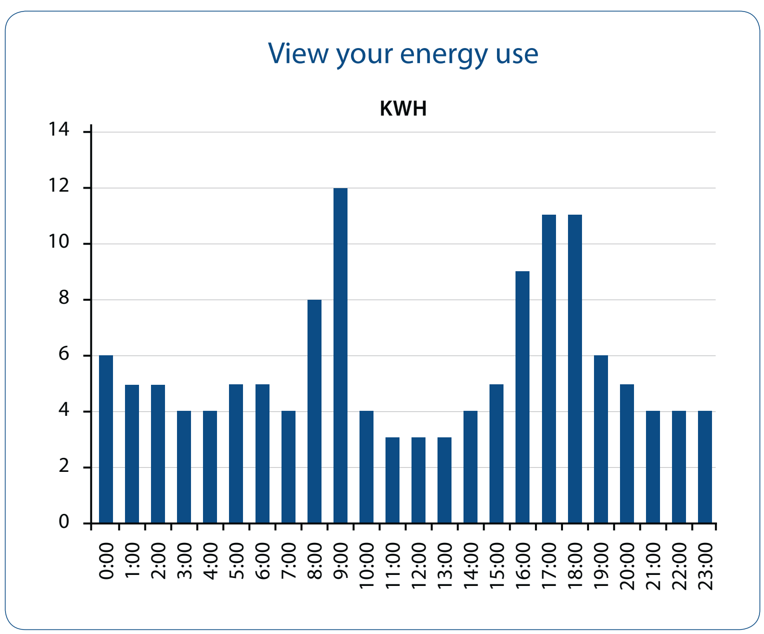
Automated Metering Infrastructure (AMI)

- Sometimes known as "smart meters"
- New meters provide customers with better energy use information
- Provide better information to utility for outage response
- Reduces need for vehicles and employees to read each meter
- No bill estimates



Manage your bill

- AMI provides more information about when and how much energy you use
- Customers can view energy use on an in-home display or on a secure website
- Provides daily, hourly and monthly energy use information



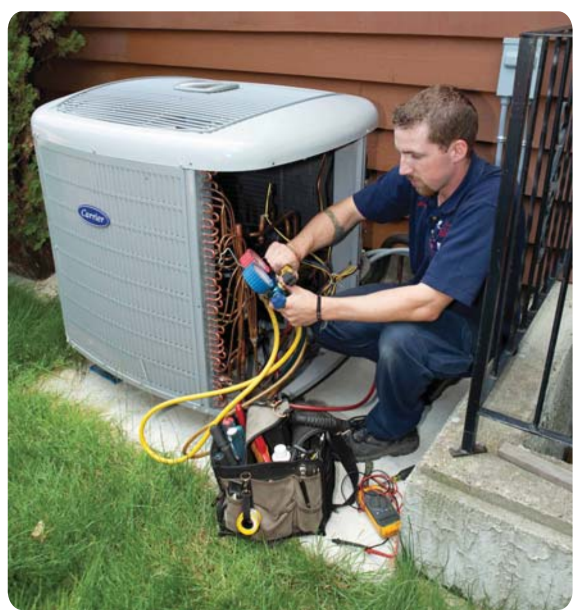
What is DSM?

Demand side management or DSM is the planning and implementation of programs designed to influence energy consumption on the customer's side of the electrical meter by encouraging customers to improve energy efficiency, reduce electricity use, change the time of use, or use a different energy source.

PowerSense is FortisBC's demand side management program. It provides programs and incentives encouraging energy efficiency for FortisBC's 161,000 direct and indirect customers.

PowerSense history

- FortisBC PowerSense is an award-winning program launched in 1989
- Cost-effective resource
- Mechanics:
  - o DSM is included in rate base
  - o Program must pass an economic test
  - o Includes both programs and incentives (rebates)
  - o Customer advisory committee
- 380 GWh of energy saved to date – enough to power about 29,700 homes for a year
- Investment of $42.5 million has resulted in 60 megawatts (MW) of capacity requirements avoided
- 2011 DSM initiatives currently meet 42 per cent of FortisBC's additional electrical needs
  - o BC Energy Plan calls for DSM to meet 50 per cent of incremental resource needs by 2020



Attachment 9
OPEN HOUSE EXIT SURVEY

Integrated System Plan feedback form

Now that you've had the opportunity to learn about the Integrated System Plan, please provide us with feedback by rating the following statements and sharing your comments below.

Priorities for capital projects

While FortisBC must always balance safety, reliability and cost when undertaking new projects, customers and communities may also have other considerations.

My priorities for capital projects also include: *(rank each for importance by circling one)*

Distance from other buildings and amenities (homes, schools, parks etc.)

1	2	3	4	5
Very important				Not at all important

Environmental values (impact on natural habitat, impact on wildlife, "no net loss" of habitat)

1	2	3	4	5
Very important				Not at all important

Visual appearance of electrical equipment

1	2	3	4	5
Very important				Not at all important

Effects on community / neighbourhood during construction

1	2	3	4	5
Very important				Not at all important

Timeliness of construction versus need for project

1	2	3	4	5
Very important				Not at all important

Flexibility for future growth

1	2	3	4	5
Very important				Not at all important

Other: ____

1	2	3	4	5
Very important				Not at all important

Other: ____

1	2	3	4	5
Very important				Not at all important

Comments: ____

Social and environmental consideration fund

Customers are telling FortisBC that they want to see additional components added when capital projects are undertaken. This could include additional visual screening (vegetation, berming or fencing), special environmental treatment, or other community specific amenities.

I would like to see FortisBC include an additional budget item to capital project budgets for social and environmental considerations? *(circle one)*

1	2	3	4	5
Strongly agree				Strongly disagree

Knowing that 1% equals $1000 for every $100,000 spent on a project, I think a reasonable amount would be: *(circle one)*

None 1% 2% 3% More than 3%

If a new electrical project (e.g. a substation or new powerlines) was built in my neighbourhood, I would want FortisBC to consider / add the following to the project…

____

____

____

Other comments:

____

____

____

Infrastructure management

FortisBC is proposing a switch from time-based infrastructure management to condition-based infrastructure management. This change in management systems will require and initial investment but will result in more cost-effective use of maintenance dollars.

The change to condition-based infrastructure management makes sense for FortisBC. *(circle one)*

1	2	3	4	5
Strongly agree				Strongly disagree

Other comments:

____

____

____

AMI

FortisBC will be filing an application with the British Columbia Utilities Commission for a new AMI program. This project proposes swapping existing electrical meters for new meters that allow a two-way information exchange. You may have also heard these called "smart meters".

Energy use information - hourly, daily or monthly data – will be available for customer viewing.

I would like FortisBC to provide customers with free in-home displays as part of the AMI project instead of interested customers purchasing their own in-home displays. *(circle one)*

1	2	3	4	5
Strongly agree				Strongly disagree

I would like FortisBC to provide customers with access to a secure website to view their energy use information. *(circle one)*

1	2	3	4	5
Strongly agree				Strongly disagree

Based on what I have heard about advanced metering or smart meter projects in other places, I have the following comments:

____

____

Before advanced metering is installed in my community, I'd like to know the following:

____

____

PowerSense - Energy efficiency programs

I would like to see FortisBC provide the following energy efficiency and conservation programs in the future.
(List types of programs or rebates for each customer group.)

Residential: ____

Commercial: ____

Industrial: ____

Lighting: ____

Irrigation: ____

PowerSense cont.

I would like to see FortisBC and Terasen Gas offer joint energy efficiency programs. *(circle one)*

1 Strongly agree	2	3	4	5 Strongly disagree

Open house feedback

The open house material presented to me tonight: *(circle one)*

	Strongly agree				Strongly disagree
Was useful and helped me understand the ISP better	1	2	3	4	5
Was a balanced perspective on the ISP	1	2	3	4	5

Final comments

Please provide any final comments:

____

____

About you

Your feedback will be considered along with technical and financial input as FortisBC prepares the ISP for filing. Feedback collected at open houses, through feedback forms and via written comments will be summarized in the consultation report which will be provided to the British Columbia Utilities Commission during the regulatory review process.

Please indicate if your electricity account is (check all that apply):
_____ Residential _____Industrial _____Wholesale _____Commercial _____Irrigation _____Lighting

Did you attend an open house? _____ Yes _____ No

_____Creston _____Castlegar _____Osoyoos _____Kelowna

How did you hear about the open house?
_____ Newspaper _____ Letter / Email of invite _____ Other (describe below)
_____ Radio _____ From a friend or colleague ______________________________

Please provide your contact information (optional):
Name ______________________________ Address ______________________________
Email ______________________________ Phone ______________________________

Deadline for feedback forms or written comment is **Friday, February 25, 2011**.
You can return written feedback forms or comments by email FBCisp@fortisbc.com
or by mail Attn: Integrated System Plan to Suite 100 -1975 Springfield Road, Kelowna, BC, V1Y 7V7

Attachment 10
OPEN HOUSE SUMMARIES

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Integrated System Plan Open House

NO OF ATTENDEES:	9
LOCATION:	Kelowna, B.C., Holiday Inn Express Hotel
MEETING DATE / TIME:	February 7, 2011 Doors open at 5:30 pm Presentation 6:10 – 6:40 pm Group questions 6:40 – 6:50 Information stations 6:50 – 7:40

ITEM #	Questions
	Group Questions
1.	• Are you working with BC Hydro to make AMI systems compatible?
	• *Yes.*
2.	• How will extra info from AMI meters help me?
	• *You will be able to better monitor your energy use with more information. For instance you could monitor your use on a secure website or in-home display that provides hourly information, rather than waiting for a bill at the end of the month which only shows the block of energy that you used during the month.*
3.	• When is the payback for smart metering?
	• *There are initial costs for the first three years of the program, then reductions over the following years.*
4.	• What is the difference between time-based and condition-based maintenance?
	• *Providing an example…time-based is similar to the regular change of your furnace filter at home. You change it every one or two months regardless of the condition of the filter. Condition-based would be if you check the factors which affect the filter like how much the furnace has been running and how dusty your home is. You would check the condition of the filter and change it only as needed.*
	Summary of Questions at Stations
5.	• Why don't you have district energy listed as a resource option on the display panels?
	• *Not included as an option for FortisBC. Provided Terasen contact name for district energy system information.*

ITEM #	Questions
6.	• Are AMI meters compatible with net metering program?
	• *Yes.*
7.	• Can you provide map of service territory?
	• *Yes, included in the handout of the PowerPoint presentation.*

**Note: Questions and responses are paraphrased.

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Integrated System Plan Open House

NO OF ATTENDEES:	7
LOCATION:	Osoyoos, B.C., Osoyoos Seniors Centre
MEETING DATE / TIME:	February 8, 2011 Doors open at 5:30 pm Presentation 6:10 – 6:45 pm Group questions 6:45 – 7:10 Information stations 7:10 – 8:20

ITEM #	Questions
	Group Questions
1.	• What is driving the cost in this project?
	• *Will be addressed a little later in the presentation with two slides that outline expected capital costs and rate increases.*
2.	• What is the growth rate used to calculate the growing energy gap (slide 14)?
	• *Includes offset by DSM but about 2.1% annually.*
3.	• What does substation in south Okanagan mean (slide 17)?
	• *New substation will be required south of Penticton, in the Kaleden area.*
4.	• Has there been any discussion about delaying any projects to meet what's happening in the economy? What are you doing?
	• *We delay projects as far as we prudently can, until they are needed.* • *People ask whether we can build up a reserve fund but as a regulated utility we are unable to do this.* • *Possible to defer costs if BCUC agrees - because of long-term benefits from Waneta Expansion we will ask to defer some costs associated with this project.* • *BCUC reviews all costs to make sure they are prudent..*
5.	• What is the insurance policy (planning reserve margin)?
	• *We would likely have a capacity purchase from BC market to cover the gap, which is not currently secured with long-term firm resources. Envisioning a new firm contract for about 10 year span. Will cover peak requirement, weather extremes and an event where we lose other generation.* • *Makes more sense than going to the market and paying whatever is the going rate.*

ITEM #	Questions
6.	• Is the power purchase a rate increase each year (slide 22)?
	• *No, once it is included, the cost is embedded and it doesn't increase again unless we must purchase more.*
7.	• What were the results of Demand Side Management open houses last year?
	• *Through our open houses in March last year, we found support for an expanded program.* • *FortisBC decided that the balanced approach was to go with the middle of the road option we provided at open houses.* • *Doubled our expenditure in 2011 as a result.*
8.	• Question on survey asks whether there is interest in joint programs with Terasen. What does that mean?
	• *Want to know if customers would like to see access to joint programs.*
9.	• What is status of rate rebalancing?
	• *Will be coming into effect in April, 2011* • *Residential will go up a little bit, commercial will come down a little bit.*
10.	• Has BCUC set the ratios? Is there equality among residential rates i.e. wholesale and non-wholesale residents?
	• *We can only look at customer classes which means we cannot deal directly with wholesale residents, only the wholesale rate its self – those wholesalers set their own residential rates.* • *Increases capped at 2.5% each year.* • *Lighting, wholesale and residential will see increases.* • *Commercial and industrial will come down.*
11.	• What is the difference in cost between regular meters and AMI meters?
	• *Only about $30*
12.	• What causes program costs then?
13.	• *Changing out the meters and installing the infrastructure to connect to the meters.* • *The up-front cost is about $40 million.* • *We expect it to be a revenue neutral project – costs in first couple of years and then decreases in following years.*
14.	• What will in-home displays cost?
	• *Very different costs depending on the level of information the display provides and whether it is connect to other systems within the house.* • *What we are wondering is should we provide some basic level of meter ($25) or should we let people buy their own?*

ITEM #	Questions
15.	• Is goal to offset peak hour use?
	• *Yes, can be part of ultimate goal, but before that, the BCUC has directed us to implement Inclining Block Rate and AMI will help customers monitor their use.*
16.	• Are you looking at time of use rates?
	• *Have some time of use rates now and will investigate more if they make sense for the FortisBC system.*
17.	• Are you looking at other places where they have already implemented smart meters?
	• *Yes, will include in our application a report which summarizes findings from other locations.* • *Good findings – customers reduce energy use just from watching in-home displays.*
18.	• Are all wholesalers are paying the same rate?
	• *Yes, with the exception of Nelson. Nelson has its own generation.*
	Summary of Questions at Stations
19.	• What is the difference between greenfield and brownfield?
	• *Greenfield projects break new ground. Brownfield projects work within the existing footprint of a project – like an upgrade in an existing substation.*
20.	• Will you include wind as option?
	• *Yes, as a clean energy option.*
21.	• Are you still considering gas turbines?
	• *Yes, as a peaking plant.*
22.	• Can you explain the difference between AMI and AMR and the difference in economics between the two?
	• *Have to actually drive by to use AMR so still require meter readers and fleet vehicles. AMI does not require that. Once the AMI system is installed you see cost reductions since you no longer need meter readers or fleet vehicles.*
23.	• What kind of in-home displays are there?
	• *There are a variety of choices, with very different costs depending on the level of information the display provides and whether it is connect to other systems within the house.*
24.	• What new home programs are we offering?
	• To find the information, visit the FortisBC website at www.fortisbc.com.

ITEM #	Questions
25.	• Could you present PowerSense information at a symposium about energy efficiency programs?
	• *Yes.*
26.	• Can I get more information about ISP elsewhere?
	• *Provided copy of PowerPoint presentation, which includes information about submitting comments and finding more information.*
27.	• Will you be adding electronics (computer equipment) to DSM program technology to save technology?
	• *Possibly, have already started some rebates for EnergyStar appliances and electronics.*
28.	• Will you rebate customers to install their own generation?
	• *FortisBC is not providing rebates for self-generation at this time.*
29.	• Can you provide district energy contact at Terasen Gas?
	• *Provided Terasen contact name.*

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Integrated System Plan Open House

NO OF ATTENDEES:	13
LOCATION:	Creston, B.C., Creston and District Community Complex
MEETING DATE / TIME:	February 9, 2011 Doors open at 5:30 pm Presentation 6:05 – 7:10 pm (group questions during presentation) Information stations 7:10 – 8:20

ITEM #	Questions
	Group Questions
1.	• What is growth rate used in your customer chart? Is growth the same in all areas?
	• *There are differences in growth rates across regions, between cities and even within different areas of cities and towns.* • *The growth shown is system-wide growth.*
2.	• Will you split into Kootenay region vs. Okanagan? Has the BCUC been asked to change postage stamp rates?
	• *No, we will not be splitting the Okanagan from the Kootenays.* • *Yes, BCUC looked at it during recent rate design process and concluded that postage stamp rates will remain.*
3.	• A new developer pays for poles and wires in a subdivision. Why do rates still go up?
	• *Customers pay for local costs, not always the upstream costs like substations required or the cost of purchasing more energy to supply new customers.*
4.	• How much is American demand influencing generation costs?
	• *The graphs in the PowerPoint presentation show only the BC market.* • *FortisBC only sells a very small amount of power in the spring and only when there is extra.* • *Any FortisBC power sold, offsets power purchase costs.*
5.	• Can you explain wholesale rates (i.e. to Nelson)?
	• *Was dealt with during Cost Of Service Analysis process – the process determined the costs on the system vs. what each customer group was paying.* • *Found commercial (6% reduction over the next few years) and*

ITEM #	Questions
	industrial were overpaying. • *Residential, irrigation, wholesale were underpaying compared to what they cost to the system as a whole.*
6.	• Shouldn't commercial customers pay more than residential?
	• *The adjustment was based only on what we charge and what it costs to serve the customer group.* • *If a customer group was paying more than they cost the system, their rates will be decreased – this includes commercial.*
7.	• Are commercial users paying the same (kWh) rate as residential?
	• *Each customer class has its own rate based on their costs to the system for instance contact centre use, meter reading etc.* • *Each customer group has its own rate (charged in kWhs).*
8.	• Is it more expensive to get energy to the Okanagan than the Kootenays since you have generation in the Kootenays?
	• *Some energy comes from the Kootenays but most of the energy used in the Okanagan comes from interconnection points with BC Hydro in the Okanagan.*
9.	• Will every meter be replaced for AMI or only new homes?
	• *Every meter will be replaced over 2012 and 2013 if BCUC agrees with the application.*
10.	• Do the rate increases compound each year? What is compound per cent increase from the chart you show in the PowerPoint presentation?
	• *They do compound each year.* • *Would be approximately 40%.*
11.	• What is smart grid?
	• *One step further than smart meters - smart grid has monitors to talk to rest of distribution system.* • *Would allow some small local generation.* • *Begins to allow control of all system below the substation level.*
12.	• Will AMI cause a rate reduction?
13.	• *No, the cost for the program offsets the savings for a net sum zero* • *We are doing this not just for economic reasons but also to provide customers with more energy use information.*
	Summary of Questions at Stations
14.	• Are you including any wind power generation?
	• *Would consider it as a clean energy option.*
15.	• Would you get involved in wood waste generation projects?

ITEM #	Questions
	• *Would consider it as a clean energy option.*
16.	• Heard that in the community that FortisBC plans to raise the head on dams by 3 feet. Is that true?
	• *No.*
17.	• Do you have any generation sources in front of BCUC now?
	• No.
18.	• Please explain the time-based vs. condition based system?
	• *Providing an example…time-based is similar to the regular change of your furnace filter at home. You change it every one or two months regardless of the condition of the filter. Condition-based would be if you check the factors which effect the filter like how much the furnace has been running and how dusty your how is. You would check the condition of the filter and change it only when it is needed.*
19.	• Will you be including a standing offer program?
	• *Yes, eventually a form of the program.*
20.	• Comment – makes more sense to have pumped storage close to load centre (in the Okanagan) rather than in the Kootenays.
21.	• Are you considering combined heat systems and other systems down to district energy centers?
	• *Not included as an option for FortisBC but provided Terasen contact name for district energy system information.*
22.	• Any other dam projects being considered other than Waneta?
	• *Have been investigating option in the Similkameen area*
23.	• What does brownfield mean?
	• *Greenfield projects break new ground. Brownfield projects work within the existing footprint of a project – like an upgrade in an existing substation.*
24.	• Are there any incentives for solar panels or other net metering?
	• No incentives through FortisBC presently. Could also check LiveSmartBC and SolarBC.
25.	• How can I access PowerSense programs? Is there a person to reach?
	• *Can access information on FortisBC website at www.fortisbc.com and there is a representative for the Kootenay region.*
26.	• Are there DSM programs for new buildings?
	• *Yes, you can access the information on the FortisBC website at*

ITEM #	Questions
	www.fortisbc.com.
27.	• When will AMI be implemented? We want it.
	• *If accepted by the BCUC, implementation will take place over 2012 and 2013.*
28.	• How much can we control on grid now vs. smart grid?
	• *Can currently see transmission and to substation level but not distribution.* • *Smart grid has monitors to communicate with rest of distribution system.* • *Begins to allow control of all system below the substation level.*
29.	• How will the Kootenay Lake Water Stewardship planning process influence the ISP – what provisions have you made?
	• *At this point it is difficult to predict the outcome of the planning process, however we have made mention of some potential implications under the Generation section of the ISP.*

Integrated System Plan Open House

NO OF ATTENDEES:	25
LOCATION:	Castlegar, B.C., Sandman Hotel
MEETING DATE / TIME:	February 10, 2011 Doors open at 5:30 pm Presentation and group questions 6:10 – 6:45 pm Information stations 6:45 – 8:20

ITEM #	Questions
	Group Questions
1.	• Can you offset planning reserve margin with operational savings?
	• *Depends on what happens in the market. Proposing to buy firm “insurance policy” at one cost, the market fluctuates.*
2.	• Is Waneta a freshet source only?
	• *We are purchasing capacity from Waneta – it allows us to make more efficient use of the energy we generate right now.* • *Provides a type of storage under the Canal Plant Agreement.*
3.	• Are there seasonal differences in Waneta’s production?
	• *Yes, but our needs are also different at different times of year and the inclusion of the Waneta project in the Canal Plant Agreement allows us to access it when needed.*
4.	• Do you have targets for distributed generation?
	• *No, we have a net metering program available but no targets*.
5.	• You offer time of use metering?
	• *Yes.*
6.	• Does it match up with net metering?
	• *It can but many of them don’t produce power when we need it the most.*
7.	• Are smart meters up for debate still or has decision been made?
	• *The Advanced Metering Infrastructure program will be going to the BC Utilities Commission later this year for a decision.*
8.	• Are you looking at smart meters in every location?

ITEM #	Questions
	• *Yes, if the project is accepted by BCUC all meters in the FortisBC system would be replaced.*
9.	• Do you have an expected cost for the AMI project?
	• *The up-front cost is about $40 million.* • *We expect it to be a revenue neutral project – costs in first couple of years and then decreases in following years.*
10.	• With in-home displays, can you tell what in your house is causing the change in energy use?
	• *Most displays tell you how much your entire house is using at a given time. You would have to do a little "sleuthing" to find which fixtures or appliances in your home are high energy users.*
11.	• Comment – thanks for doing the open house. FortisBC is making a big step coming out to the community.
12.	• How does load growth compare in Kootenays vs. the Okanagan?
	• *There are differences in growth rates across regions, between cities and even within different areas of cities and towns.* • *The growth shown on the slide is system-wide growth.*
13.	• What is the total amount of power generated in BC and what is the total use?
	• *Don't have the exact figure. Could perhaps get this kind of information from BC Hydro.*
14.	• How much energy are you buying from the United States?
	• *We don't buy much from the US. We bought 9% from market last year compared to about 45% that we generate.*
	Summary of Questions at Stations
15.	• Do you know what kind of power you are buying (i.e. coal fired)?
	• We do not monitor what is the source of the power that we buy. We purchase energy from a marketer and don't deal directly with the generating company. We know that the marketer could be purchasing the energy from any number of sources (Wind/Hydro/Coal/Gas).
16.	• Since FortisBC pays taxes and line charges to municipalities, why shouldn't local areas pay for infrastructure screening if they wish instead of adding this to the project cost?
	• *Lines and substations are paid for by all customers through rates. We are proposing a consistent approach for all new projects.*
17.	• Is FortisBC interested in making distributed generation more feasible for ratepayers to participate?
	• *There are no incentives at this time.*
18.	• What kind of generation is FortisBC looking for to match up with

ITEM #	Questions
	wind generation? How much wind could our system sustain?
	• Wind is a non-firm source of generation so FortisBC would also require a firm source as a simple cycle gas turbine peaking plant or small hydro in addition to wind.
19.	• Are you looking at Run of the River?
	• *Not specifically, although we would consider small hydro as a clean energy option.*
20.	• What will be regulatory process be for AMI? When?
	• *FortisBC will be making application to the BCUC later this year. Once submitted, the BCUC will outline the regulatory process required.*
21.	• Have you heard about smart meter issues in other jurisdictions such as privacy and EMF?
	• *As part of the application process, FortisBC will provide a summary of the experiences other areas.*
22.	• Have you decided what technology you will include in the AMI application?
	• *We are still investigating technologies.*
23.	• How aggressively will Terasen pursue district energy systems?
	• *Provided contact name for Terasen district energy system information.*
24.	• What were the efficiency gains from ULE projects?
	• *The efficiency gains from the ULE projects were recognized under the Canal plant agreement. The total recognized gain was approximately 10% additional capacity.*
25.	• Is the FortisBC system ready for electric cars?
	• *No, but part of the ISP planning is to look at future energy use trends and ensure that we are when the time comes.*
26.	• What are you doing with South Slocan facilities? Why are we changing things?
	• *Some of the facilities in the South Slocan area are coming to the end of their life span and are no longer appropriate for office use. FortisBC is considering all facilities in the area including Terasen Gas facilities to make sure we can meet our needs.*
27.	• How do you get condition based information back to our control system?
	• *The first part of the program would be information gathering to record the current condition of our infrastructure.*
28.	• Will AMI be able to accommodate time of use metering?

ITEM #	Questions
	• *Yes*

Attachment 11
GOVERNMENT STAKEHOLDER MEETING SCHEDULE

Integrated System Plan – Government Stakeholder Meetings
February – March 2011

Organization	Date	Time	Location
MLA West Kootenay West	Feb 24, 2011	12:30 pm	MLA's office, Castlegar
District of Summerland Council	Feb 28, 2011	8:30 am	Town Hall
City of Kelowna Council	Feb 28, 2011	1:30 pm	City Hall
Town of Princeton Council	March 7, 2011	7 pm	Town Hall
City of Trail Council	March 14, 2011	7 pm	Town Hall
Regional District of Okanagan Similkameen Board	March 17, 2011	1:30 pm	Regional District office

Attachment 12

IILUMINA RESEARCH PARTNERS SUPER GROUP SUMMARY

FORTISBC

An Assessment of Public Reactions to the FortisBC Integrated System Plan

March 15 2011

PN 7105

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"Opinions are formed in a process of open discussion and public debate, and where no opportunity for the forming of opinions exists, there may be moods—moods of the masses and moods of individuals, the latter no less fickle and unreliable than the former—but no opinion."

- Hannah Arendt

Table of Contents

Executive Summary

30,000 Foot View

Overall, customer perceptions of the Integrated System Plan (ISP) are positive.

- Customers identified moderate to high levels of support for implementing the proposed initiatives across each of the ISP focus areas; however, there isn't a strong willingness to pay for these initiatives.

Demand Side Management + Resource Planning + Capital Expenditures + AMI + Revenue Requirements = Integrated System Plan

Demand Side Management	Resource Planning	Capital Expenditures	AMI	Revenue Requirements	Integrated System Plan
• Conservation Attitudes (Pgs. 6, 7, 30, 31, 32) • Joint Conservation Programs (Pg. 63)	• Planning Reserve Margin (Pgs. 9, 52) • Contractual Agreements (Pgs. 9, 53)	• Social and Environmental Components (Pgs. 10, 11, 55, 56, 57) • Condition Based Management (Pgs. 12, 58, 59)	• AMI (Pgs. 13, 65-72)	• Price Sensitivity (Pgs. 8, 28) • Willingness to pay higher electricity prices (Pgs. 52, 57)	• Overall ISP Rating (Pgs. 14, 78) • Understanding of ISP (Pgs. 74, 75) • Balanced Perspective of ISP (Pg. 76)

> *"I'm glad I came tonight because I gained a better understanding of where and how our daily electricity is generated, how it is provided and what plans are being made for the future to meet expanding needs. While I don't look forward to increased costs in future, I must say I approved of the methods being planned to keep costs down and to spread out costs over time. It seems like Fortis has their brains on straight."*
>
> *"I was somewhat surprised to know of a 40 to 41% increase in our rates over the next 5 years which I think is too excessive in my view."*

- (Green) More Receptive Compared to Other Results in the Report: Average ratings of 85% or higher for strongly/somewhat agree or definitely/probably should be considered.
- (Amber) Neutral Compared to Other Results in the Report: Average ratings of 61%-85% for strongly/somewhat agree or definitely/probably should be considered.
- (Red) Less Receptive Compared to Other Results in the Report: Average ratings of 60% or lower for strongly/somewhat agree or definitely/probably should be considered, or average ratings of 40% or higher for strongly/somewhat disagree or definitely/probably should NOT be considered.

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Customer Priorities

Reliability of energy ranked most critical. Conserving energy and helping customers manage consumption ranked higher (more critically important) after FortisBC's presentation, while keeping costs down and generating power in BC ranked lower.

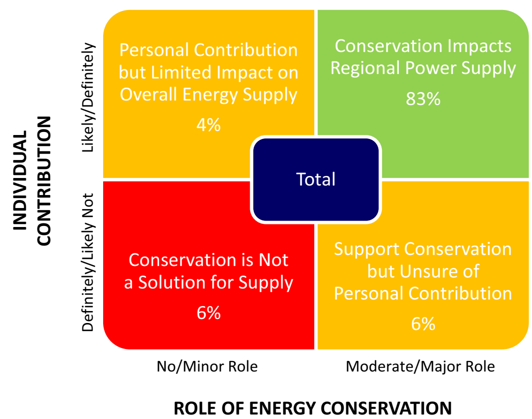
Pre FortisBC Presentation Ranking of Planning Challenges Based on Total Respondents (n=115)	**Post FortisBC Presentation Ranking of Planning Challenges** Based on Total Respondents (n=115)
Ensuring reliable power 79%	Ensuring reliable power 80%
Keeping down costs/ managing future costs 67%	Conserving energy/ reducing energy consumption 73%
Generating power within BC 63%	Helping customers manage consumption 72%
Conserving energy/ reducing energy consumption 54%	Keeping down costs/ managing future costs 70%
Helping customers manage consumption 51%	Generating power within BC 70%
Minimizing environmental impacts 50%	Minimizing power outages 49%
Minimizing power outages 46%	Minimizing environmental impacts 43%
Meeting the goals of the BC Clean Energy Act 44%	Meeting the goals of the BC Clean Energy Act 41%
Meeting the goals of the BC Energy Plan 29%	Meeting the goals of the BC Energy Plan 39%
Minimizing visual impacts of infrastructure/equipment 18%	Minimizing visual impacts of infrastructure/equipment 25%

For further information please see pages 38 to 50.

Conservation

Almost three quarters of customers identified conserving energy /reducing energy consumption (73%) and helping customers manage consumption (72%) as critically important challenges for planning for future energy and infrastructure needs.

- 83% of participants indicate that they feel conservation can have an impact on the regional supply of power (they feel they can individually contribute to lowering overall levels of energy usage and believe that managing consumption can positively contribute to energy supply). In contrast, only 6% of customers believe that conservation can play little or no role in managing energy supply and that they personally cannot contribute to the regional energy supply.



There are no regional differences in these results.

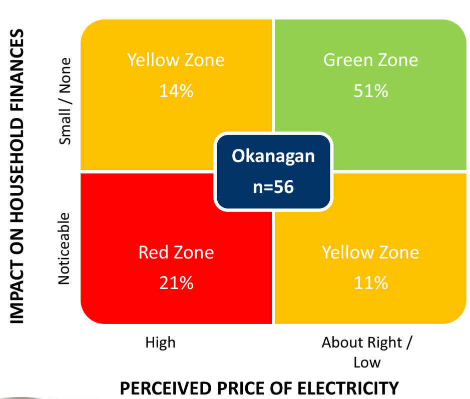
***Please note that results may not round to 100% as "no answers" are not reported.**

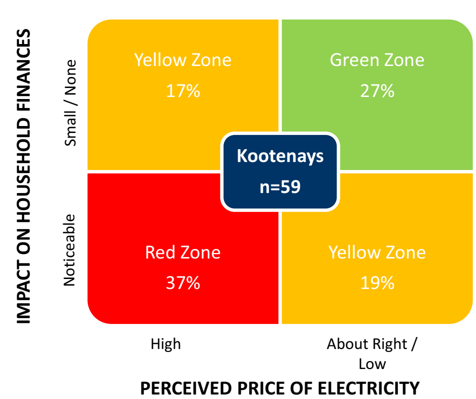
For further information please see pages 30, 31 and 32.

Revenue Requirements

Electrical rate increases are a concern across all potential ISP related initiatives. Kootenay participants are more price sensitive; and consequently, they are less willing to accept rate increases for ISP initiatives.

- Looking at current perceptions of electricity prices, considerably more Kootenay participants fall into the red zone (feel prices are high and that rates noticeably impact household finances) and significantly fewer are in the green zone (price is right and impact is low) compared to Okanagan participants.
- In general, Kootenay participants are less willing than Okanagan participants to pay more for initiatives. See pages 52 and 57.





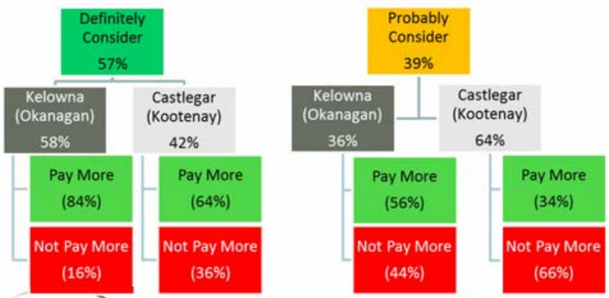
For further information please see pages 28, 52, and 57.

Resource Planning

Overall, 96% of customers support the Planning Reserve Margin and 75% support the use of contractual agreements to fill small gaps in short term energy supply rather than building new generation resources.

- Although 96% of participants support the Planning Reserve Margin, only 60% are willing to pay higher electricity rates for it.
- Among those who state the planning reserve margin should <u>definitely</u> be considered, 24% are not willing to pay more for it - this jumps to 58% amongst those who state the planning reserve margin should <u>probably</u> be considered.
- Of those who wouldn't pay higher prices to support the Planning Reserve Margin, 69% are from the Kootenay region and 31% are from the Okanagan region.

96% Support for Planning Reserve Margin
(Total Respondents, n=115)



For further information please see pages 52 and 53.

- 75% of participants strongly or somewhat agree with using contractual agreements to fulfill small gaps in short term energy supply rather than building additional generation resources.
- There are no differences in support for using contractual agreements between Business and Residential participants.
- 20% of Castlegar participants neither agree or disagree to using contractual agreements to fill small gaps in short term energy supply rather than building additional generation resources.

75% Support for Contractual Agreements
(Total Respondents, n=115)

Strongly Agree 24%
Somewhat Agree 51%

Capital Expenditures - Social and Environmental Components

Customers identified impact on customer electricity rates as the most important social and environmental consideration when determining future project and equipment expenditures.

- 36% of participants state social and environmental components such as additional visual screening, special environmental treatment, or other community specific amenities should <u>definitely be considered</u> in determining future project budgets, while 53% state they should <u>probably be considered</u>. However, only half (50%) of participants who state these components should definitely/probably be considered are willing to pay higher electrical rates to include these components in capital project budgets.
- In the context of different factors to consider for future project and capital expenditures, visual appearance ranks the lowest. Only 14% of participants rate visual appearance as very important.

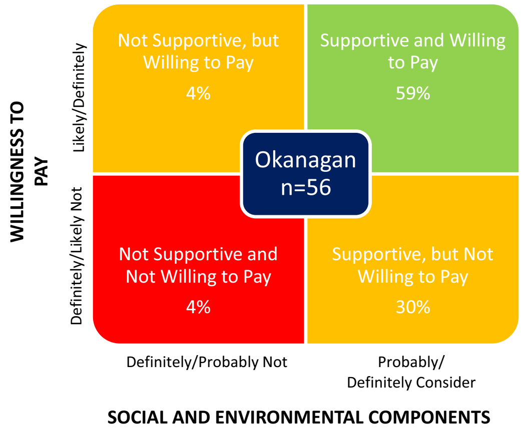
	Very Important	Important but Not Critical
Impact on Customer Rates	70%	27%
Flexibility for Future Growth	55%	41%
Environmental Values	52%	37%
Distance from Buildings and Amenities	51%	41%
Effects on Community/Neighbourhood During Construction	23%	54%
Timeliness of Construction Versus Need for Project	22%	56%
Visual Appearance of Electrical Equipment	14%	50%

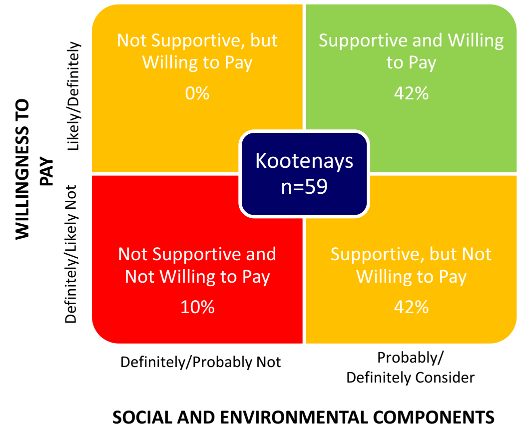
For further information please see pages 55, 56, and 57.

Capital Expenditures - Social and Environmental Components

Support for including social and environmental components in future capital budgets and willingness to accept higher rates to include these components differed by region.

- Although participants from both regions support social and environmental components in future capital budgets, participants from the Kootenay region are significantly less willing to pay for social and environmental components with higher rates compared to participants from the Okanagan region.
- Overall, 1% was seen as a reasonable amount to add to the capital project budget by over half of participants.





Please note results may not round to 100% as "no answers" are not reported.

For further information please see pages 55 , 56 and 57.

Capital Expenditures – Condition-Based Management

The majority of customers support the implementation of condition-based management rather than time-based management.

- 92% of respondents support the change from time-based to condition-based management with just over one-third (37%) state this process definitely should be considered. 55% state the change to condition-based management probably should be considered.
- The top two reasons mentioned by participants for why condition-based management should be considered are:
  - Condition-based management means lower costs overall, and
  - Costs are lower because infrastructure is maintained/fixed when needed as opposed to on a fixed schedule.

> - *"Components should be replaced when needed, not because of time use policy."*
> - *"Cost effective in the long run."*
> - *"It makes sense as maintenance work is based on need not an arbitrary time span."*
> - *"I believe there will be a cost saving and reduced impact on the environment."*
> - *"Not enough info. "condition based" might have things till too late (i.e. timeliness vs. just-in-time)."*
> - *"There is no definite relationship between condition based maintenance and cost savings. The investment could provide little or no return."*

For further information please see pages 58 and 59.

AMI

While significantly more customers selected having in-home displays provided as part of the AMI project, some hedged their selection with comments like only if there is no additional cost or if it does not increase electricity rates.

Provide In-home displays 59%	Optional In-home Displays 40%
• 30% say an in-home display will educate and make them more aware of their energy usage.	• 17% say they want the freedom to choose whether to have an in-home display and another 17% don't care or don't see the value of an in-home display.

- Participants who would prefer an in-home display provided as part of the AMI project appear to have a stronger interest in understanding their energy usage.
- Participants who prefer in-home displays to be optional indicate being disinterested in monitoring their usage or feel they can manage their consumption on their own or via a secure website.
- 60% of respondents indicated that they strongly agree with offering an incentive program if in-home displays are an optional component of AMI.
- If in-home displays are optional, most customers would pay up to 50 dollars for the technology.
- The most mentioned concerns by participants about AMI are about the impact of AMI on electricity rates and the possibility of implementing time of use rates as well as the implications of time of use rates on electricity bills.
- Customers are looking for more information on AMI (9%) and are concerned about the cost implications (13%).
- 79% of customers indicate that they definitely or probably would use a secure FortisBC website to track energy usage. However, access to a computer and computer literacy is an issue for 19% of customers.

For further information please see pages 65 to 72.

Overall Perceptions of the ISP

Overall, Super Group participants were supportive of the FortisBC Integrated System Plan.

- 82% of participants did not find the FortisBC presentation confusing or difficult to understand.
- 94% strongly or somewhat agreed that FortisBC's presentation helped them understand the ISP better.
- 83% strongly or somewhat agreed that FortisBC's presentation provided a balanced perspective on the ISP.
- 75% strongly or somewhat agreed that the ISP fulfills the objective of planning for the electrical needs of the next 20 to 30 years.

- *"Good presentation - appreciated the room full of experts. Excellent display boards. Come out feeling like I was part of the team."*
- *"It was interesting - it helped my understanding of hydro energy and happy to see your care."*
- *"Very impressed. Lots of information. There was no discussion on alternative methods of hydro."*
- *"After this presentation I strongly agree that everyone should have a smart meter installed in their home. Before this presentation I would have been against this idea. Great presentation and this was time well spent. Thank you! Keep up the great work!"*

For further information please see pages 74 to 79.

Communications

Customers want to understand how different initiatives are going to benefit them and what the bottom line cost implications are for them. Also important to customers is information on how to better manage their energy consumption.

- Customers want FortisBC to provide additional information in several areas:
  - How various initiatives will directly benefit them.
  - The rate implications of implementing new programs. Specifically, they would like information on the size of potential rate increases associated with new programs/processes and exactly how much it will increase their electrical bill.
  - How to better manage their energy consumption.
  - Cost implications of AMI and in-home displays and how to use AMI to reduce energy consumption.
  - How time of use rates work and how time of use rates would impact their lives and electricity bills (even though FortisBC is not planning to implement time of use rates at this time).

- *"How will this benefit me - I see how it benefits Fortis."*
- *"I would like to see more information in $ signs as to how my FortisBC bill will be affected. Have customers service representatives available to figure that out for individual customers."*
- *"Concerned about cost of meter and possibility of charging for peak usage time."*
- *"The cost and a breakdown of the advantages of the program (AMI)."*
- *"If FortisBC wants consumers to use less energy, it will force FortisBC to educate consumers of the value of in-home displays and conserving energy."*

For further information please see pages 59, 61, 62, 71, 72, 74, 79, 84 and 85.

Customer Class Differences

Both Residential and Business customers are looking for information on conservation; however, the communications should be designed to meet their different informational needs.

- The current price for household electricity is viewed as too high by Residential customers (53%) but about right by Business customers (69%) (See page 28).
- Business customers are more likely to be aware of the ISP prior to attending the Super Groups (See page 34).
- Business customers are more likely than Residential to believe that FortisBC can supply as much energy as is needed in the short term and long term (See pages 36 and 37).
- Residential customers provided more negative comments about the ISP (25% versus 6%) compared to Business customers and appear to want a deeper level of understanding about FortisBC's initiatives, particularly on how it impacts their electrical bill. Additional information and education about future FortisBC initiatives may strengthen Residential support of new initiatives like AMI (See page 79).
- The type of conservation programs desired differ between Residential (i.e., education on how to reduce energy consumption) and Business customers (i.e., lighting rebates) (See page 62).
- The ISP presentation was found to be more difficult or confusing for Residential customers than Business customers (See page 74).

Background and Methodology

Project Overview

Background

FortisBC Inc. is an integrated regulated electric utility based in Kelowna, British Columbia. Focused on the safe delivery of reliable and cost-effective electricity, FortisBC serves approximately 160,000 customers in the southern interior of B.C. including residential, commercial (general service), industrial, lighting, irrigation and wholesale electricity customers. FortisBC employs over 500 people in British Columbia and is an wholly owned subsidiary of Fortis Inc., the largest investor-owned distribution utility in Canada.

Project Purpose

FortisBC is currently developing an Integrated System Plan. As part of its regulatory approval process, FortisBC is undertaking consultation in the communities it services through open houses and direct dialogue with key stakeholders as well as general communications and one-on-one discussions.

Illumina Research Partners has been asked to conduct research that will enable FortisBC to obtain detailed customer feedback on the Integrated System Plan. The research will enable FortisBC to better understand the impacts of this plan on the different regions and customer classes. The Super Group research process is used to provide a balanced representation of all customer classes in both the Kootenay and Okanagan regions, providing feedback from customer classes which had been under-represented during previous public open houses.

Overall Business Objective

Engage a representative cross-section of FortisBC customers in a meaningful dialogue and consultation on the ISP to understand customer knowledge, beliefs, perceptions and concerns regarding the Integrated System Plan.

Research Objectives

Overall Research Objectives

- Understand overall perception of ISP: positive, neutral, negative.
- Understand customer knowledge, beliefs, perceptions and concerns on the different components of the ISP: Resource Plan, Capital Expenditures, Revenue Requirements, and Demand Side Management (as can be gathered based on the questionnaire and information gathered during the super groups).
- Understand the impacts that changes due to the Integrated System Plan will have on different customer classes (residential, commercial, industrial, wholesale and irrigation).
- Refine communications messages so that subsequent communications are able to explain the Integrated System Plan in a way that resonates with each customer class.

Specific Research Questions to Address

- What is the customer context in regard to views on electrical prices, conservation, energy supply, and important challenges for the region?
- How do customers feel about the Planning Reserve Margin, would customers pay higher prices to include this?
- What social and environmental factors are most important to customers when determining future energy expenditures? Are customers willing to accept an increase in rates for social and environmental factors?
- Do customers agree with a condition-based infrastructure management approach?
- What is customer feedback on the AMI program? Should in-home meters be provided to all customers as part of the AMI project or optional? If optional, is an incentive program needed?
- For each component, how willing are customers to pay higher prices for electricity for these changes in order to meeting the planning objectives?
- What areas of the ISP are unclear to customers and need to be communicated differently?

Methodology – Overview

Session Agenda

1. Participant Registration
2. Welcome by Illumina Research Partners
3. Completion of Part 1 of the Integrated System Plan Questionnaire
4. Introduction and Overview of the Evenings' Purpose
5. Presentation by FortisBC
6. Question and Answer Period
7. Exploration of FortisBC Information Booths
8. Completion of Part 2 of the Integrated System Plan Questionnaire

Super Group Method Details

- One Super Group was held in Kelowna on February 23, 2011 and a second one was held in Castlegar on February 24, 2011.
- In each Super Group, FortisBC gave a 30-minute presentation on the Integrated System Plan. A formal 15 minute Question and Answer session was provided following the presentation.
- FortisBC provided 5 information booths which participants had 40 minutes to explore. FortisBC representatives were available to answer questions at each booth.
- Participants were requested to complete surveys pre and post session. The pre-survey was completed prior to the presentation upon entry to the meeting, and the post-survey was completed following the information booth session. Questionnaires were developed using a format that allowed for scanning of the results into a database rather than data entry of results. This method increases accuracy of results.

Methodology – Recruiting Strategy

- Individuals were randomly selected by Illumina Research, from FortisBC's customer database. These individuals were invited by telephone to attend a 'focus group.' This 'focus group' is referenced as a Super Group within this report as the size of the groups are much larger compared to a typical focus group.
- The customer classes represented were: residential, general service (commercial), industrial Primary/Transmission, lighting and irrigation. A quota system was used to ensure that a minimum number of members of each of these customer classes was registered to attend the session. The table below provides these numbers. Please note that quotas are based on a recruitment goal, however, not all recruited will show for the event.
- Screening questions did not specifically screen out respondents who may have attended a FortisBC Super Group in 2007 or 2009. Screening questions were in place to limit the number of people who have previously attended any focus groups.
- Illumina Research Partners is a member of the The Marketing Research and Intelligence Association (MRIA), which is a Canadian not-for-profit association representing all aspects of the market intelligence and survey research industry. The MRIA code on conduct for members specifies that for research utilizing customer databases as the source for sample selection, the source of the list and identity of the Client must be revealed, if requested by the participant. The protocol for recruiters was that if requested, participants were to be told the groups were sponsored by FortisBC to discuss energy and infrastructure needs for the future.
- Local participants received a $75 cash honorarium for attending. Individuals driving in excess of 1.0 hour were given a larger incentive of $100.

Customer Class Representation

	Kelowna		Castlegar	
Customers By Class	**Recruit Quota**	**Actual**	**Recruit Quota**	**Actual**
Total	**70**	**56**	**70**	**59**
Residential	49 (70%)	38 (68%)	49 (70%)	43 (73%)
General Service/Commercial	13 (19%)	11 (20%)	13 (19%)	9 (15%)
Industrial Primary/Transmission	2 (3%)	0 (0%)	2 (3%)	2 (3%)
Lighting	3 (4%)	3 (5%)	3 (4%)	2 (3%)
Irrigation	3 (4%)	2 (4%)	3 (4%)	3 (5%)

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The Two Part Questionnaire Process

- After a brief welcome to the Super Group session participants were asked to complete Part 1 of a questionnaire. This questionnaire gathered demographics and gained insight into customer views of current planning challenges before FortisBC presented any information regarding the ISP. The Part 2 questionnaire was provided after the FortisBC content presentation, question and answer period, and information booth exploration.

Part A Questionnaire

- Demographic information on age, gender, employment status, home ownership, type of dwelling, number of residents in dwelling, and usage of heating and cooling energy sources
- Perceptual questions on the acceptability of current electricity prices and the impact on household finances
- Perception of power supply in the short term (2 to 5 years) and long term (20 years from now)
- Attitudes about the role that conservation/managing consumption plays on energy supply (individually and overall)
- Awareness of the ISP prior to the Super Group sessions
- Pre-test assessment of the importance of various challenges to consider when planning for the future
- Ranking of the planning challenges attributes
- Awareness of the PowerSense program

Part B Questionnaire

- Post-test assessment of the importance of various challenges to consider when planning for the future
- Support for contractual agreements
- Support of, and likelihood to pay higher prices for a Planning Reserve Margin
- Rating of the importance of various social and environmental components when determining future project and equipment expenditures
- Support of, and likelihood to pay higher prices including social and environmental factors in budgets
- Opinions on what a reasonable amount would be to add to each project budget for social and environmental factors
- Support for switching to condition-based management
- Perceptions and support for AMI components (in-home displays, incentive programs for purchasing in-home displays, price point for in-home displays, likelihood to use a website for tracking energy usage
- Support for joint conservation programs between FortisBC and Terasen Gas
- Overall assessment question regarding the ISP
- Overall feedback on the presentation

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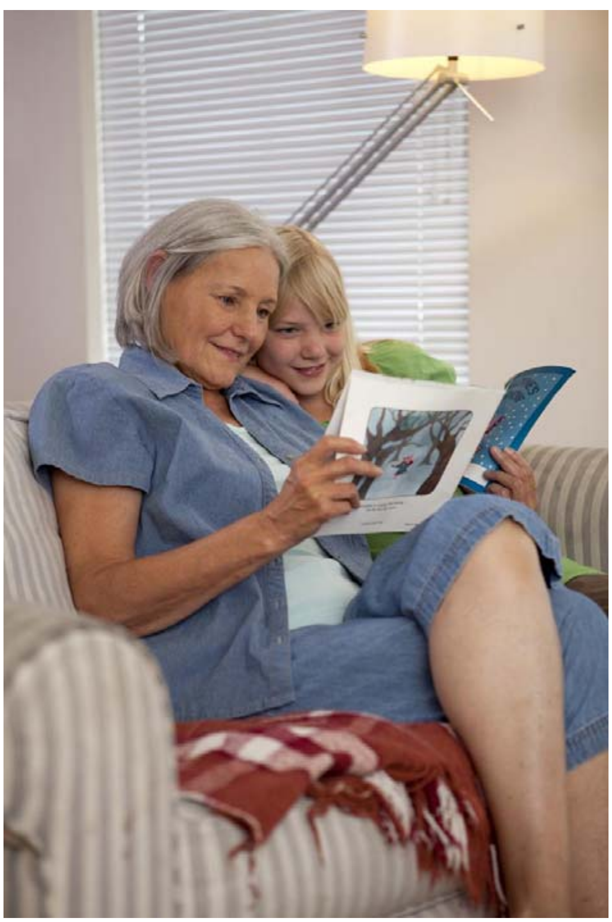
Data Report



Customer Demographics

General Demographics

The age, gender and employment characteristics were similar for both sessions of Super Group participants.

Questionnaire Data	Total n=115	Kelowna (Okanagan) n=56	Castlegar (Kootenay) n=59
Age			
18 to 34	16%	13%	19%
35 to 54	31%	32%	31%
55 and more	53%	55%	51%
No answer	0%	0%	0%
Gender			
Male	55%	54%	56%
Female	45%	46%	44%
Employment Status			
Working full-time	38%	41%	36%
Working part-time	14%	16%	12%
Unemployed or looking for a job	8%	4%	12%
Stay at home full-time	5%	7%	3%
Student	3%	2%	5%
Retired	30%	30%	31%
No answer	1%	0%	2%
Number of People in Household			
1	15%	16%	14%
2	43%	46%	41%
3	18%	13%	24%
4 or more	22%	21%	22%
No answer	2%	4%	0%

Screener Data	Total n=115	Kelowna (Okanagan) n=56	Castlegar (Kootenay) n=59
Income			
Under $40,000	23%	21%	25%
$40,000 - $60,000	20%	29%	12%
$60,001 - $80,000	15%	11%	19%
Over $80,000	21%	23%	19%
No answer	21%	16%	25%

Indicates significant regional differences at a 95% confidence level

Household/Energy Consumption Characteristics

Kootenay participants identify significantly higher usage of electricity to heat their homes.

	Total n=115	Kelowna (Okanagan) n=56	Castlegar (Kootenay) n=59
Account Type (Multiple Mentions)			
Residential	94%	93%	95%
General Service/Commercial	21%	23%	19%
Industrial Primary/Transmission	1%	0%	2%
Lighting	6%	11%	2%
Irrigation	5%	7%	3%
Home Ownership			
Own	84%	91%	78%
Rent	16%	9%	22%
Dwelling Type			
Single detached house	73%	71%	75%
Townhouse or duplex	8%	11%	5%
Apartment building	6%	9%	3%
Mobile home	6%	5%	7%
Basement Suite/Suite	3%	2%	3%
Other	3%	0%	7%
No answer	1%	2%	0%
Square Footage			
Less than 800 sq. ft.	3%	4%	3%
800 to less than 1200 sq. ft.	28%	25%	31%
1200 to less than 1600 sq. ft.	25%	20%	31%
1600 to less than 2000 sq. ft.	16%	13%	19%
2000 to less than 2500 sq. ft.	14%	18%	10%
More than 2500 sq. ft.	12%	20%	5%
No answer	2%	2%	2%

	Total n=115	Kelowna (Okanagan) n=56	Castlegar (Kootenay) n=59
Fuel Used to Heat House (Multiple Responses)			
Natural Gas	52%	55%	49%
Oil	2%	4%	0%
Propane	3%	4%	2%
Electricity	50%	39%	59%
Wood	22%	18%	25%
Other	4%	7%	2%
No answer	1%	2%	0%
Main Heating System			
Central air	46%	57%	36%
Electric baseboards	18%	18%	19%
Hot water baseboards / radiator	3%	2%	3%
Heat pump (air or ground)	10%	11%	8%
Wood, gas or electric fireplace	11%	7%	15%
Other (please describe):	10%	4%	15%
Don't Know/No answer	3%	2%	3%
Air Conditioning in Home			
Yes, central air	38%	57%	20%
Yes, a window unit	23%	29%	19%
No	37%	13%	61%
No answer	1%	2%	0%

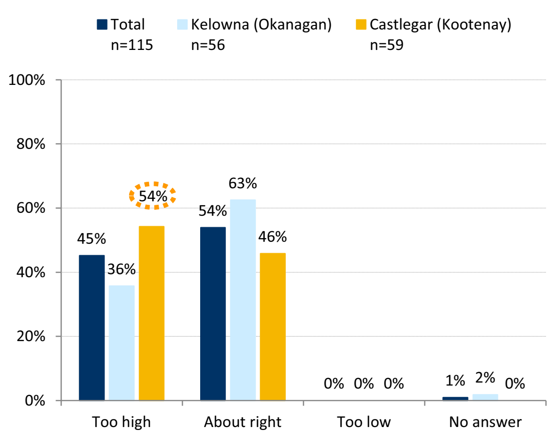
Indicates significant regional differences at a 95% confidence level

Price Sensitivity

Super Group Respondent Profiles – Price Sensitivity

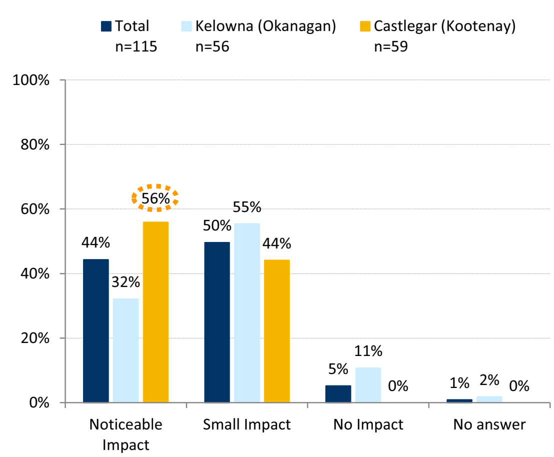
Half of customers find energy prices 'about right' and identify that prices have only a small impact on their finances. Kootenay residents are comparatively more price sensitive.

Attitude Toward Current Price of Household Electricity



	Total n=115	Residential n=81	Business n=32
About right	54%	47%	69%
Too high	45%	53%	28%
Refused	1%	0%	3%

Impact of Household Electricity Bill on Household Finances



Indicates significant regional differences at a 95% confidence level

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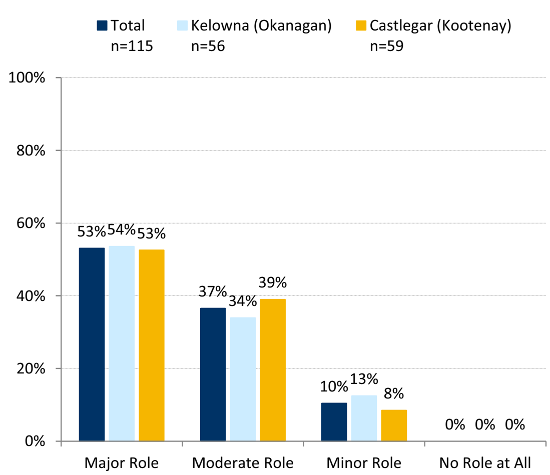
Conservation Attitudes

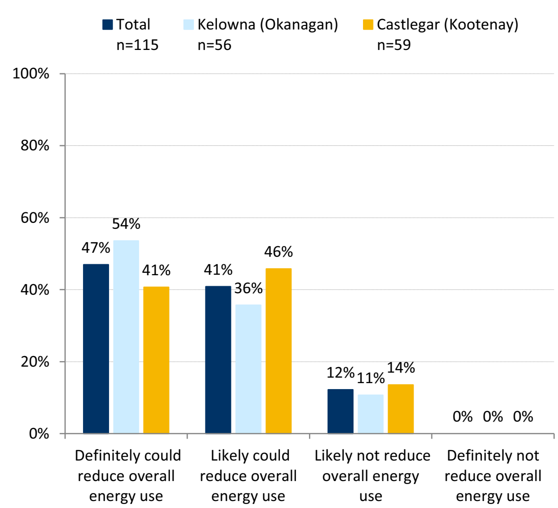
Super Group Respondent Profiles – Conservation Attitudes

FortisBC customers in both regions believe that energy conservation can play a moderate to major role in power supply. Most people do feel they as individuals can contribute to reducing overall energy usage in their regions.

The Role of Energy Conservation to Regional Power Supply



Customer Contribution to Energy Conservation

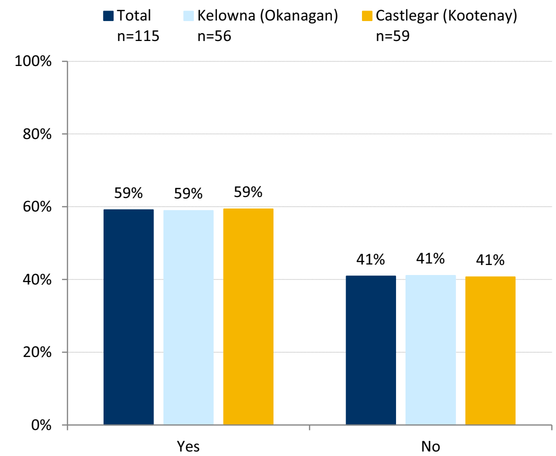


Indicates significant regional differences at a 95% confidence level

Super Group Respondent Profiles – Conservation Awareness

Almost 60% of customers identify awareness of FortisBC PowerSense rebates or programs. Almost half of those aware had heard of rebates for light bulbs/energy efficient lightbulbs.*

Awareness of FortisBC PowerSense Energy Efficiency Rebates or Programs



***Please see the following page for a list of the rebates and programs identified.**

Super Group Respondent Profiles – Conservation Awareness

Of the various PowerSense rebates and programs customers are most aware of rebates on energy efficient light bulbs, appliances, and windows.

Customer Awareness of FortisBC PowerSense Energy Efficiency Rebates or Programs

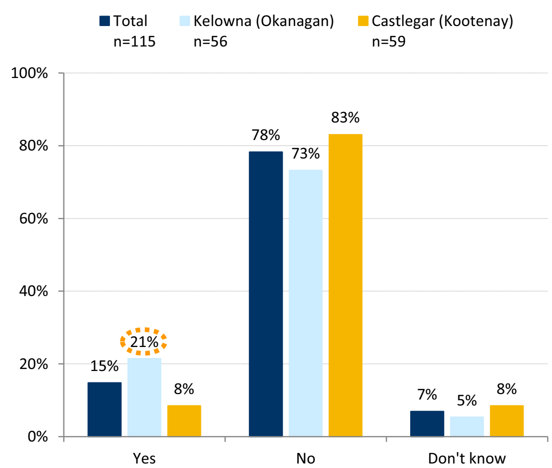
Total Mentions	Total n=68	Kelowna (Okanagan) n=33	Castlegar (Kootenay) n=35
Lightbulbs/rebate for lightbulbs/lighting/rebate on more efficient lightbulbs/CF bulbs	47%	42%	51%
Appliances/energy-efficient appliances/replacement of old home appliances	15%	15%	14%
Windows/rebate for newer windows/installing energy-efficient windows/window upgrades/(doors)	13%	15%	11%
Furnaces/more efficient furnaces/furnace changeout/upgrades/updated furnaces	9%	6%	11%
Heat pumps/geothermal heating	9%	12%	6%
Heating/rebates on energy-efficient heating/changing heating systems/rebates or replacing heating and cooling equipment	9%	9%	9%
Hot water heater/replacing hot water tanks/energy-efficient water heaters	7%	6%	9%
Insulation/home insulation rebate/program for better insulation	7%	12%	3%
Home energy rebates/rebate on house repairs to keep energy consumption down	6%	3%	9%
Making equipment more efficient/upgrading existing equipment/changing industrial equipment to more efficient models	6%	6%	6%
Solar panels/program for solar hot water/solar B.C.	6%	9%	3%
Home building with high R value/new home construction	4%	6%	3%
PowerSmart/PowerSense (not specified further)	4%	3%	6%
VFDs/incentive to install VFD on motors/VFD for motor starting	4%	0%	9%
Christmas lights/exchanging older Christmas lights for rebates on LED ones	3%	6%	0%
FLIP program for business	3%	6%	0%
Had a power audit completed/evaluation of energy usage	3%	3%	3%
Clotheslines/free clotheslines	1%	3%	0%
Miscellaneous single mentions	4%	3%	6%
Don't know/not stated	6%	3%	9%
Refused/No answer	3%	0%	6%

Awareness Levels of the FortisBC Integrated System Plan

Awareness of the Integrated System Plan

The majority of participants were unaware of the ISP prior to the FortisBC Super Group Town Hall Forum. Awareness was higher at the Kelowna session.

Awareness of the Integrated System Plan Prior to the FortisBC Super Group Session



Awareness of the Integrated System Plan Prior to the FortisBC Super Group Session (Comparison by Customer Type)

	Total n=115	Residential n=81	Business n=32
Yes	15%	6%	34%
No	78%	86%	59%
Don't know	7%	7%	6%

Business customers are more likely to be aware of the ISP prior to attending the Super Groups.

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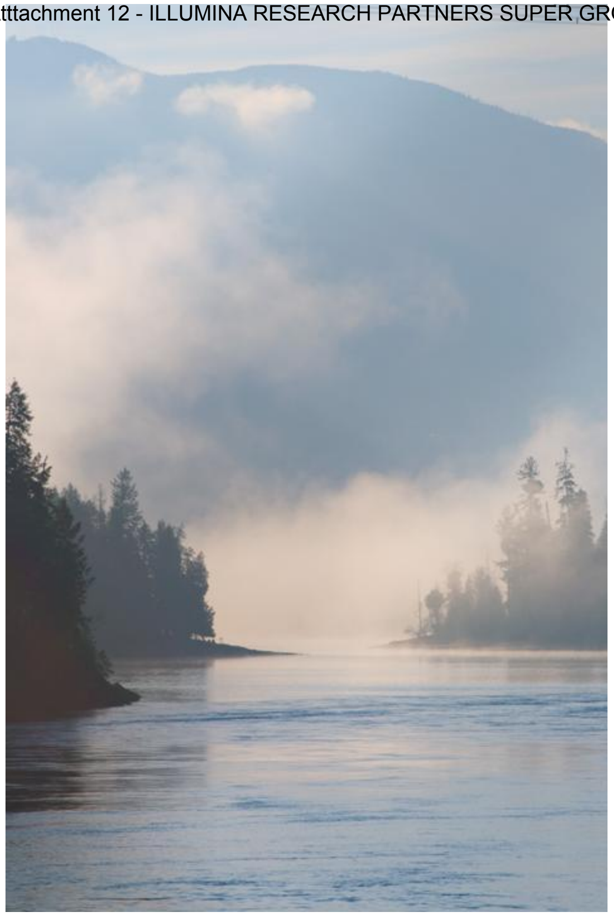
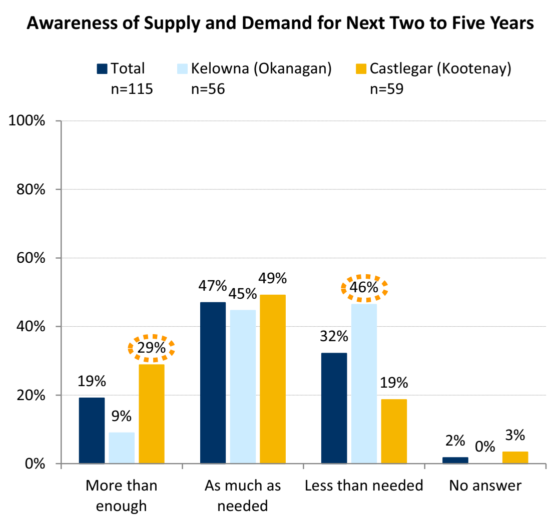
Indicates significant regional differences at a 95% confidence level



Customer Perceptions and Priorities

Awareness of Short-Term Supply and Demand

Customers in both the Okanagan and Kootenay regions perceive that energy supply will meet demand in the short-term. The Okanagan region perceives a greater deficit in short term supply.



Awareness of Supply and Demand for Next Two to Five Years (Comparison by Customer Type)

	Total n=115	Residential n=81	Business n=32
More than enough	19%	20%	16%
As much as needed	47%	40%	66%
Less than needed	32%	40%	16%
Refused	2%	1%	3%

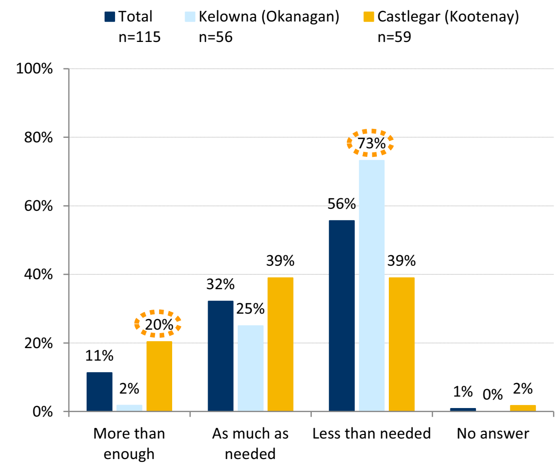
Business customers are more likely than Residential to believe that FortisBC can supply as much energy as needed in the short term.

Indicates significant regional differences at a 95% confidence level

Awareness of Long-Term Supply and Demand

Customers in both the Okanagan and Kootenay regions perceive that energy supply will not meet demand in the long term. The Okanagan region perceives a greater deficit in long term energy supply.

Awareness of Supply and Demand for Next Twenty Years



Awareness of Supply and Demand for Next Twenty Years (Comparison by Customer Type)

	Total n=115	Residential n=81	Business n=32
More than enough	11%	11%	13%
As much as needed	32%	25%	50%
Less than needed	56%	63%	38%
No answer	1%	1%	0%

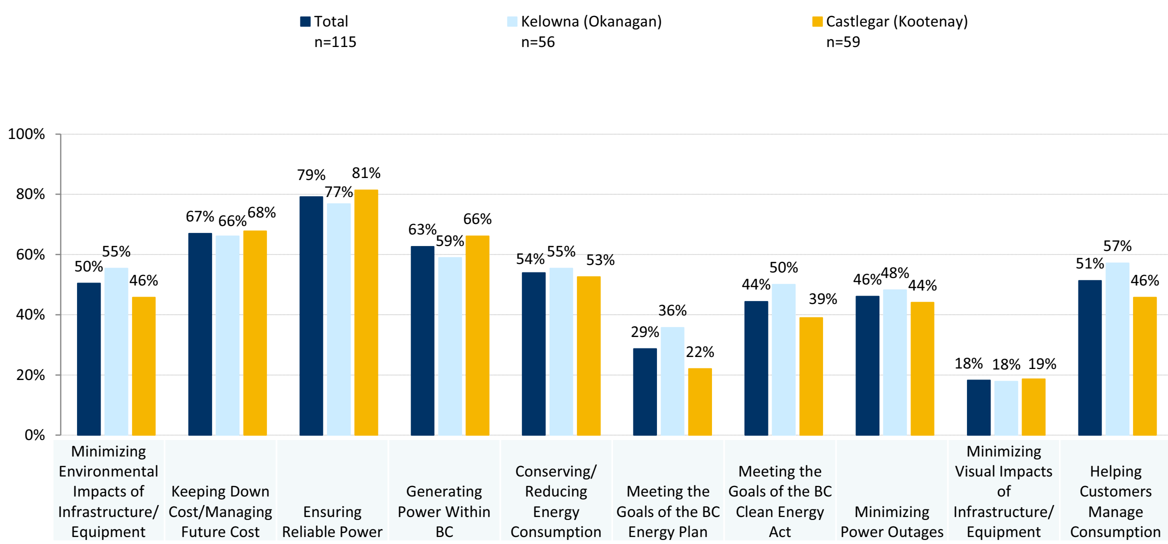
Business customers are more likely than Residential to believe that FortisBC can supply as much energy as needed in the long term.

Indicates significant regional differences at a 95% confidence level

Perceptions on Planning Challenges

Customers in both regions identify reliability, managing cost, and local power generation as top factors to consider when developing energy plans for the future.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs
“Critically Important Only” – Pre-Test Survey

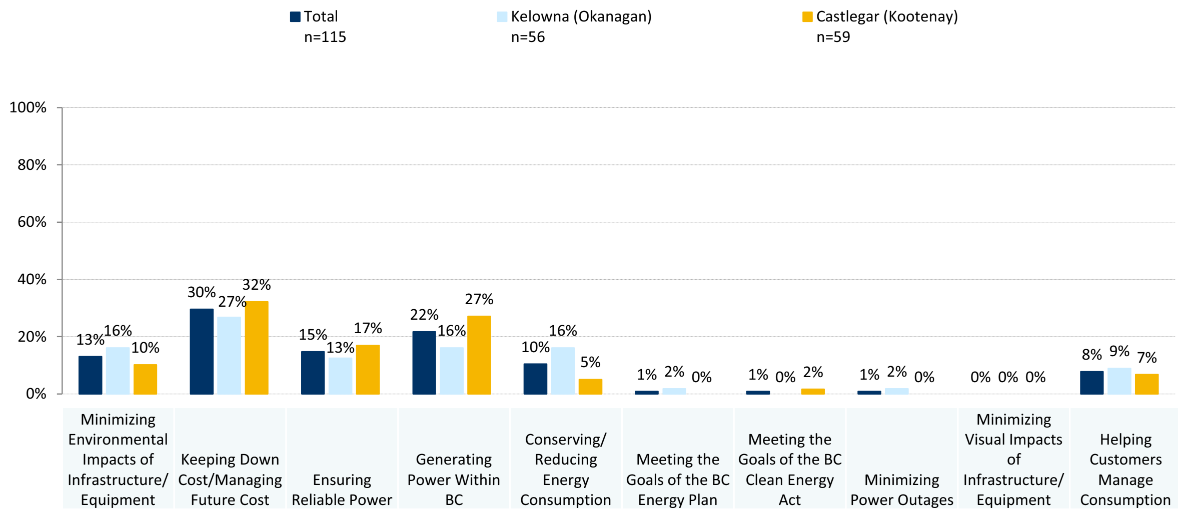


Reliability was selected as critically important by more customers than any other challenge. However, when asked to rank the challenges, cost became the one most important consideration. See the next page.

Perceptions on Planning Challenges

Managing cost is identified as the one most critically important planning challenge to address, followed by generating power within BC.

The ONE "Critically Important" Challenge to Address (Ranking of Challenges)



Perceptions on Planning Challenges

Why Customers Chose a Specific Challenge as Most Important

Total Mentions	Total
Minimizing the environmental impacts of electrical infrastructure and equipment	**n=15**
We have to save the environment/we only have one Earth and we have to make it last/we must minimize the impact on the Earth/if the environment is spoiled nothing else will matter/they care about the environment	67%
Important for future generations/the legacy we leave for future generations	13%
Cost-effective/cheaper in the long run/keep costs low/saves money (non-specific)	7%
Less energy used/would mean less energy consumption/to stop being wasteful	7%
Miscellaneous single mentions	7%
So it continues/sustainability	7%
I am on a fixed income/limited income/I am poor/concern for people on welfare and pensions/it is either electricity or food	7%
Don't know/not stated	7%
Keeping down the cost/managing the future cost of electricity charged to customers	**n=33**
I am on a fixed income/limited income/I am poor/concern for people on welfare and pensions/it is either electricity or food	36%
Rates are too high/electricity is expensive/our electric bill is too high	21%
Other specific cost mentions (ie. Cost of living is out of control, everyone has so much debt, if cost is unaffordable all other challenges are not going to matter, could Fortis instead cut back on some of their salary costs?)	18%
Benefits all/we all gain/critical to everyone	9%
Important to sustain reasonable standard of living/high-priced power will result in lower living standards	6%
Support local economy/required for growth of the region/to help support and maintain our province/helps our economy/money should be spent in our province	6%
Ensuring a reliable source of power	**n=16**
Important to have a reliable supply/ensure a reliable source of power/people and businesses depend on reliable power/reliable energy more important than low cost	38%
Supply is critical to meet demands/today's activities need power/growing demand for power	19%
Safety mentions/to ensure the safety and security of our communities/for commercial safety	13%
Consistent supply keeps a community running smoothly/otherwise the whole city stops	6%
Important to sustain reasonable standard of living/high-priced power will result in lower living standards	6%
So it continues/sustainability	6%
So people stay happy	6%
So we can avoid importing energy/to continue to be self-sufficient/rely on ourselves	6%
We have to save the environment/we only have one Earth and we have to make it last/we must minimize the impact on the Earth/if the environment is spoiled nothing else will matter/they care about the environment	6%
Better ability for Fortis to control their costs/keep their costs down	6%
Miscellaneous single mentions	13%
Don't know/not stated	6%

Perceptions on Planning Challenges

Why Customers Chose a Specific Challenge as Most Important

Total Mentions	Total
Generating power within BC rather than importing it from outside B.C	**n=25**
Local energy means local jobs/creates employment/keeps jobs in B.C.	20%
So we can avoid importing energy/to continue to be self-sufficient/rely on ourselves	20%
Lower consumer cost/keeping costs down to customers/lower cost to end-user	16%
We have many/enough sources/we have more than enough power	16%
Support local economy/required for growth of the region/to help support and maintain our province/helps our economy/money should be spent in our province	12%
Cost-effective/cheaper in the long run/keep costs low/saves money (non-specific)	12%
Better ability for Fortis to control their costs/keep their costs down	8%
Important for future generations/the legacy we leave for future generations	8%
Important to have a reliable supply/ensure a reliable source of power/people and businesses depend on reliable power/reliable energy more important than low cost	8%
So we can control our costs and supply in B.C./important to control our own energy	8%
Benefits all/we all gain/critical to everyone	4%
Supply is critical to meet demands/today's activities need power/growing demand for power	4%
The other goals depend on this being achieved/it addresses many other things on the list/if you deal with this then the other things are taken care of	4%
Miscellaneous single mentions	20%
Conserving/reducing our energy consumption	**n=11**
Less energy used/would mean less energy consumption/to stop being wasteful	*
The other goals depend on this being achieved/it addresses many other things on the list/if you deal with this then the other things are taken care of	*
Cost-effective/cheaper in the long run/keep costs low/saves money (non-specific)	*
Better ability for Fortis to control their costs/keep their costs down	*
Important for future generations/the legacy we leave for future generations	*
Education/information is powerful/if people are knowledgeable they are better able to make a difference	*
We have to save the environment/we only have one Earth and we have to make it last/we must minimize the impact on the Earth/if the environment is spoiled nothing else will matter/they care about the environment	*
Lower consumer cost/keeping costs down to customers/lower cost to end-user	*
Important to have a reliable supply/ensure a reliable source of power/people and businesses depend on reliable power/reliable energy more important than low cost	*
Reduce building plants/reduced need to build infrastructure	*

***Please note only themes with a base size of n=15 were provided.**

Perceptions on Planning Challenges

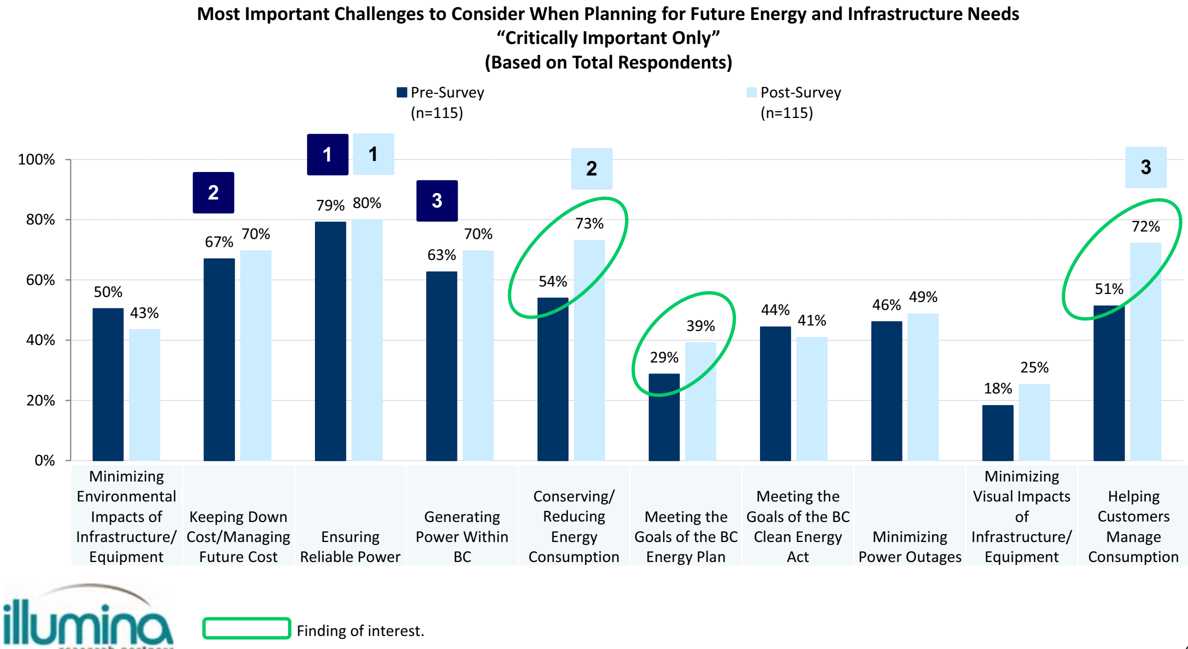
Why Customers Chose a Specific Challenge as Most Important

Total Mentions	Total
Meeting the goals of the BC Energy Plan	**n=1**
Miscellaneous single mentions	*
Meeting the goals of the BC Clean Energy Act	**n=1**
Important for future generations/the legacy we leave for future generations	*
Minimizing power outages	**n=1**
Consistent supply keeps a community running smoothly/otherwise the whole city stops	*
Helping customers understand how to manage their energy consumption	**n=8**
Education/information is powerful/if people are knowledgeable they are better able to make a difference	*
Few people understand the way it works and need constant reminding/people have a hard time finding ways to reduce consumption and won't because they don't think it makes a difference	*
Important to have a reliable supply/ensure a reliable source of power/people and businesses depend on reliable power/reliable energy more important than low cost	*
Less energy used/would mean less energy consumption/to stop being wasteful	*
So it continues/sustainability	*
Supply is critical to meet demands/today's activities need power/growing demand for power	*
The other goals depend on this being achieved/it addresses many other things on the list/if you deal with this then the other things are taken care of	*
Lower consumer cost/keeping costs down to customers/lower cost to end-user	*

***Please note only themes with a base size of n=15 were provided.**

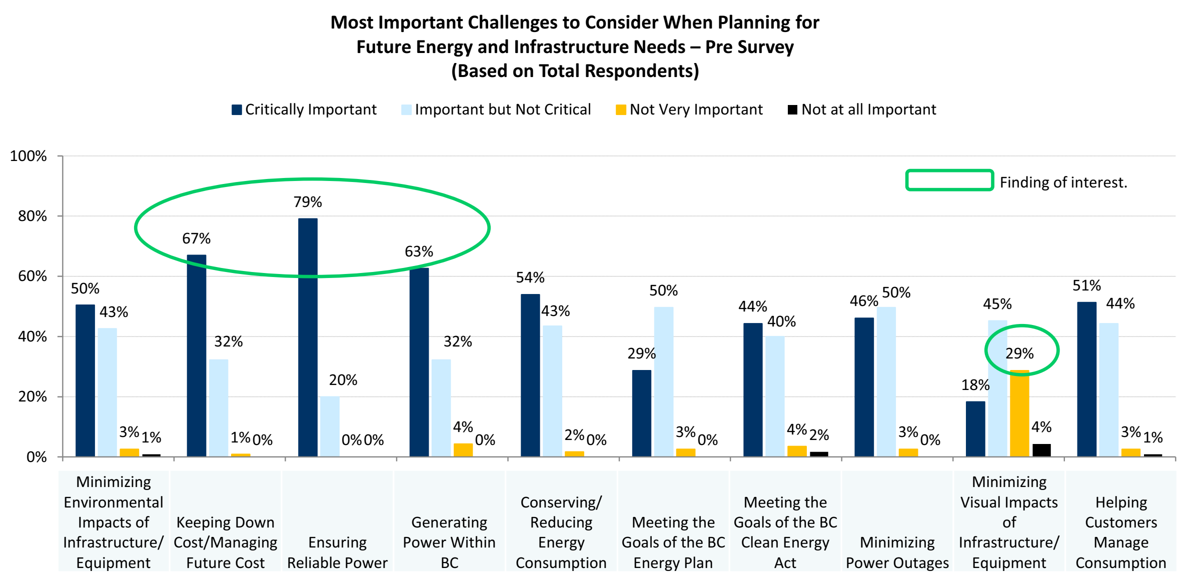
Perceptions on Planning Challenges

The importance of various planning challenges was asked of customers in both pre and post surveys. Reliability remained the most important, but conservation and helping customers manage consumption became notably more important.



Perceptions on Planning Challenges

Overall, reliable power, managing cost, and local power generation were critically important to address, while meeting the goals of the BC Clean Energy Act and minimizing visual impacts were important but not critical.



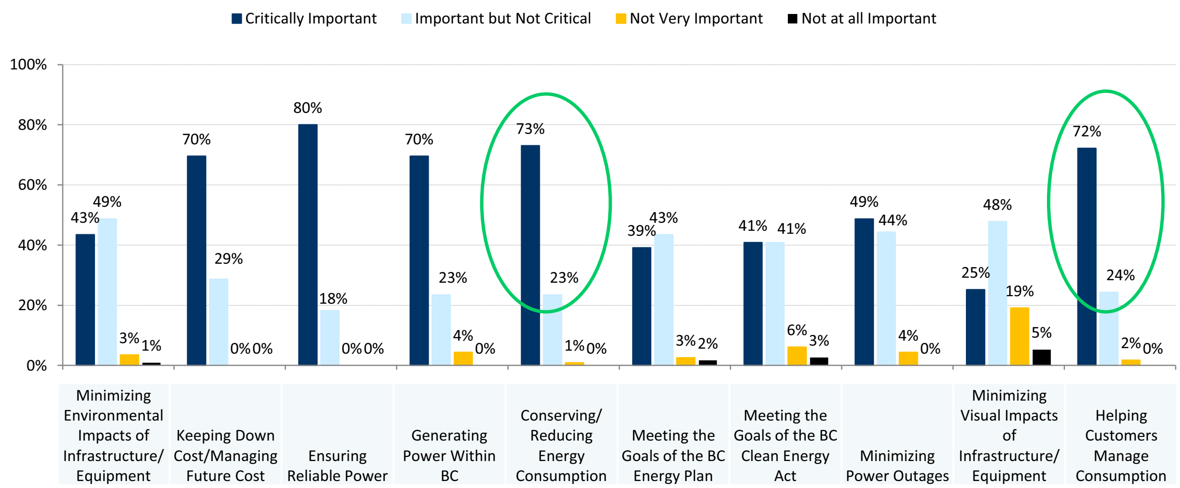
Minimizing the visual impacts of Infrastructure and Equipment was the only planning consideration or challenge that was considered by a substantial number of customers as not very important.

***Please note results may not round to 100% as "don't know" is not reported.**

Perceptions on Planning Challenges

While the importance of most attributes remained similar before and after the FortisBC ISP presentation, the importance of conserving energy and helping customers manage consumption grew substantially.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs – Post Survey (Based on Total Respondents)



***Please note results may not round to 100% as "don't know" is not reported.**

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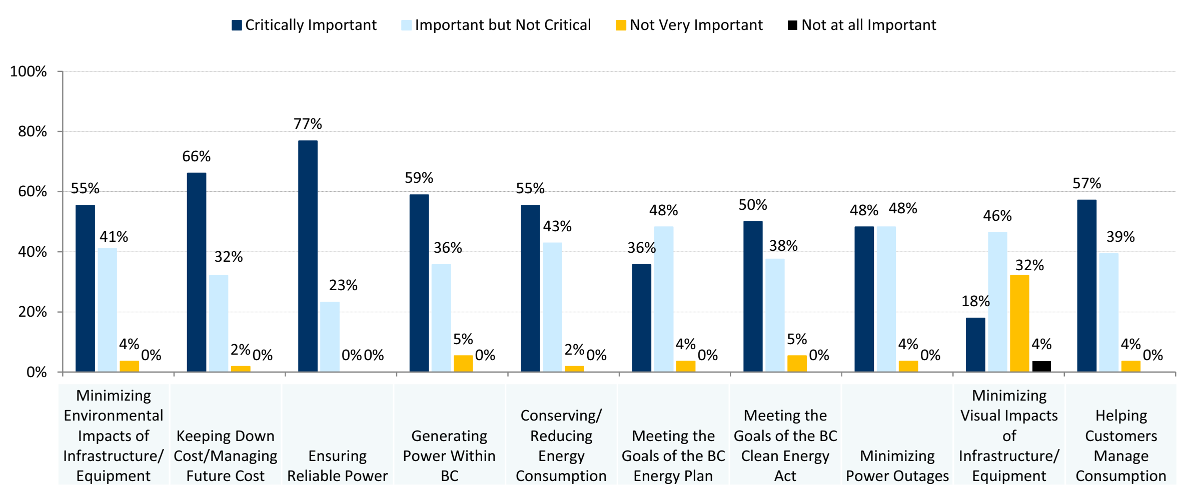
Finding of interest.

Pre Survey Perceptions on Planning Challenges - Okanagan

The top three critically important challenges in the Okanagan region are reliable power, managing costs and generating power with BC. Minimizing visual impacts of infrastructure and equipment rated lowest in critical importance.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs – Pre Survey (Kelowna/Okanagan Respondents)



***Please note results may not round to 100% as "don't know" is not reported.**

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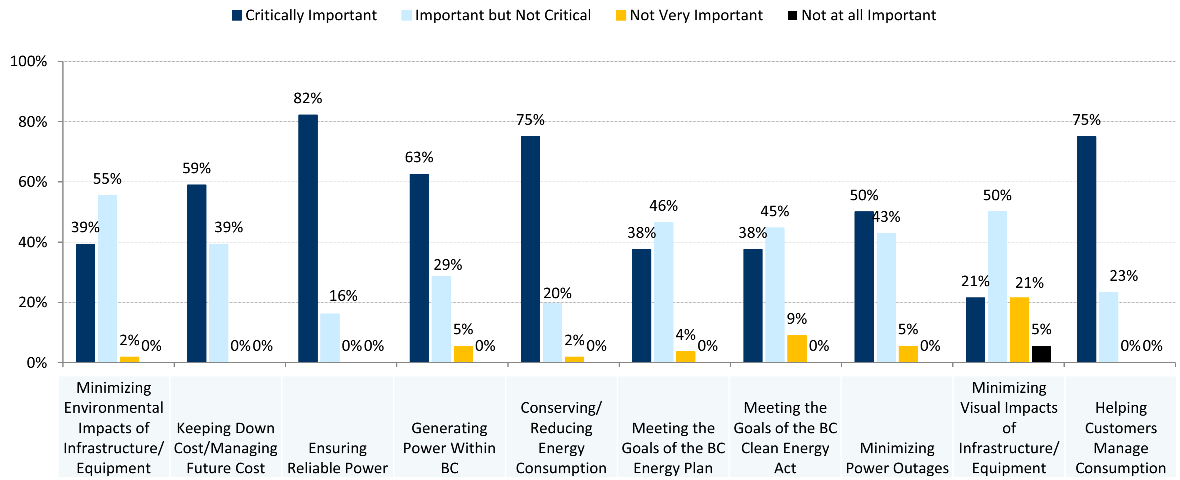
Post Survey Perceptions on Planning Challenges - Okanagan

The importance of conservation and helping customers manage consumption increased significantly in critical importance among Okanagan participants after the FortisBC presentation.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs – Post Survey (Kelowna/Okanagan Respondents)

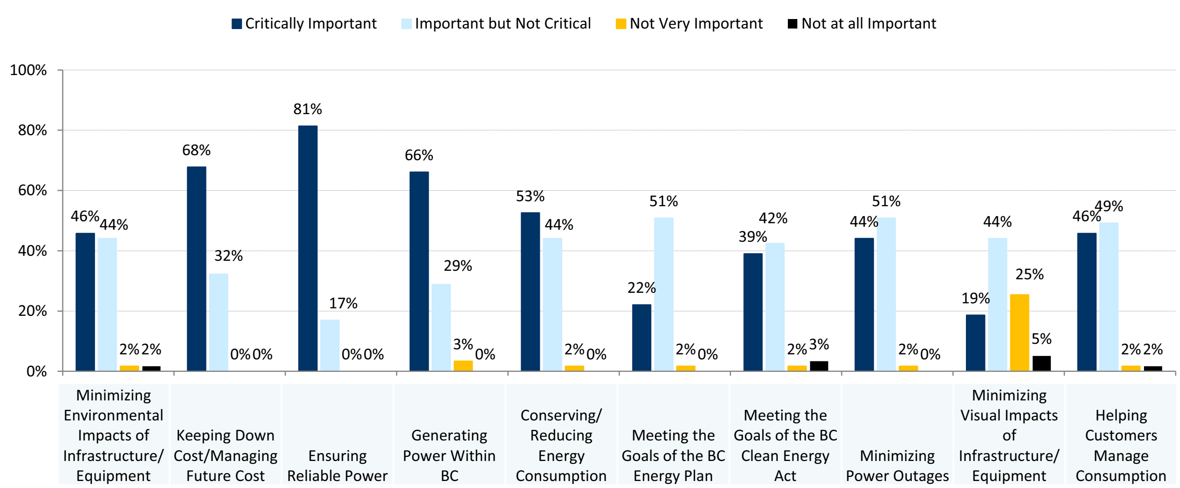


***Please note results may not round to 100% as "don't know" is not reported.**

Pre Survey Perceptions on Planning Challenges – Kootenay

Among Kootenay residents, the top three critically important planning challenges are reliability, managing costs and generating power within BC. Minimizing visual impacts rated lowest in critical importance.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs – Pre Survey (Castlegar/Kootenay Respondents)

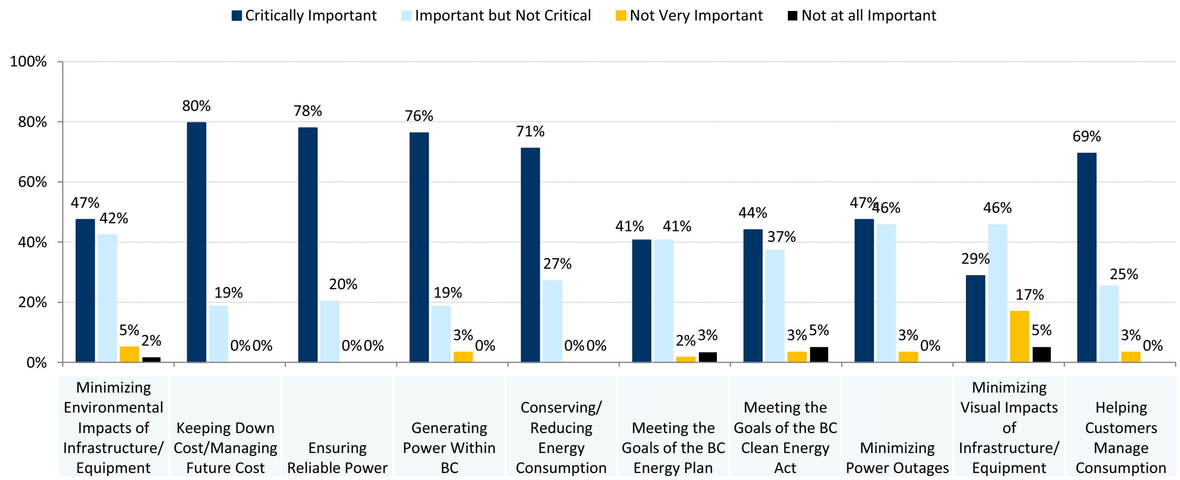


***Please note results may not round to 100% as "don't know" is not reported.**

Post Survey Perceptions on Planning Challenges - Kootenay

Similar to the Okanagan region, the importance of conserving energy and helping customers manage consumption increased in critical importance after the FortisBC presentation.

Most Important Challenges to Consider When Planning for Future Energy and Infrastructure Needs – Post Survey (Castlegar/Kootenay Respondents)



***Please note results may not round to 100% as "don't know" is not reported.**

Perceptions on Planning Challenges

Customers identified that alternate energy sources are an area to be considered in future energy planning. The need to consider health hazards is also identified.

Other Planning Challenges Not Identified

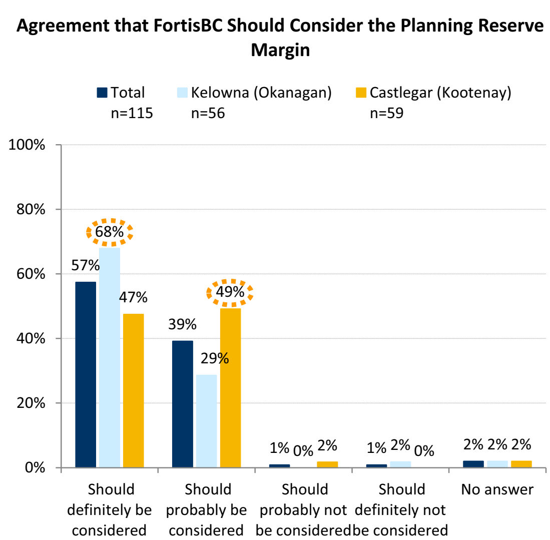
Total Mentions	Total n=65	Kelowna (Okanagan) n=32	Castlegar (Kootenay) n=33
Solar energy/solar power incentives to the grid/metering for solar	9%	13%	6%
Health issues/hazards of power lines and transmitters	6%	13%	0%
Alternate energy sources/renewable energy/combining alternative sources of energy production	6%	6%	6%
Wind as an energy source/wind power/metering for wind	6%	9%	3%
Educating the public on energy consumption/ways to reduce consumption	5%	3%	6%
Introduction of Smart Meters/Smart Metering program costs	5%	0%	9%
Interconnection to the grid to ensure secure sources/minimal down time/uninterrupted service	5%	6%	3%
Other cost mentions (ie. Who is the competition to help keep costs down?, sharing the cost of service correctly to all rate groups, inflation has to be considered when budgeting ahead for power that must be purchased)	5%	3%	6%
Buying power from residents and helping people to accomplish this/implementing a system to allow customers to sell back to the grid	3%	6%	0%
Provide rebates/incentives to help people with energy costs	3%	6%	0%
Keep B.C.'s power in B.C./impact on B.C. and Canada of power being supplied to the U.S.	3%	6%	0%
Individual vs. corporate usage/industrial energy savings	3%	0%	6%
Move to more electrical products/future impact of electric cars	3%	6%	0%
Other infrastructure mentions/overhead transmission vs. underground/visual impact of infrastructure in tourism area	3%	6%	0%
Other specific energy source mentions (ie. Role of nuclear energy, vast amounts of natural gas available to generate power)	3%	3%	3%
Getting salmon back in our rivers/rebuild salmon runs	3%	0%	6%
Hydroelectric dams concerns/potential future of hydroelectric dams/ensuring stability of dams while replacing aging gas trunk lines and hydro facilities	3%	6%	0%
Moral and ethical responsibility vs. profit/not thinking about our people and how they will cope with the impact	3%	3%	3%
Miscellaneous single mentions	6%	3%	9%
Nothing	28%	22%	33%
Don't know/not stated	6%	0%	12%

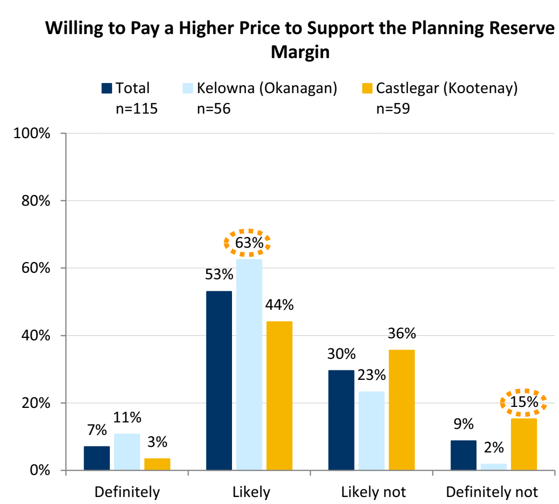
Resource Planning

The Resource Plan is a long range planning document used by electrical utilities to identify future power supply requirements.

Planning Reserve Margin

The Planning Reserve Margin is viewed quite positively with only a few individual customers against the idea. However, over one-third are not willing to pay increased electrical rates to support the Planning Reserve Margin.





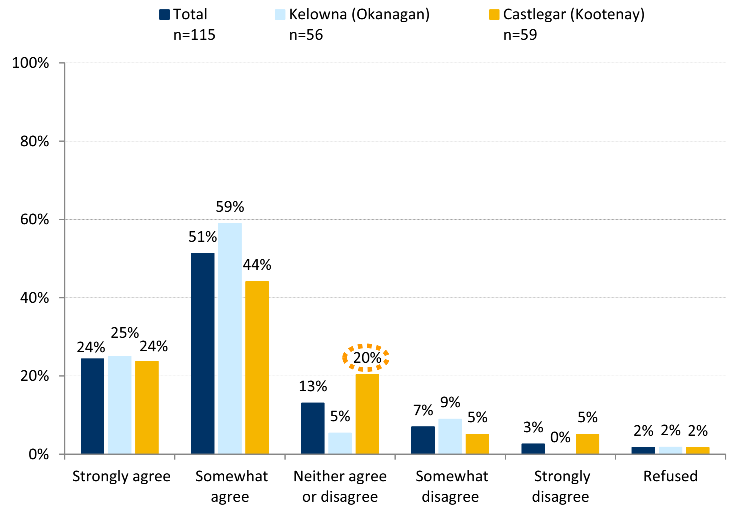
Okanagan residents are more positive about the Planning Reserve Margin and are more willing to pay a higher price to introduce this concept.

Indicates significant regional differences at a 95% confidence level

Resource Plan—Contractual Agreements

Three quarters of customers strongly or somewhat agree with using contractual agreements to fulfill small gaps in short term energy supply rather than building additional generation resources.

Agreement with the Use of Contractual Agreements



Indicates significant regional differences at a 95% confidence level

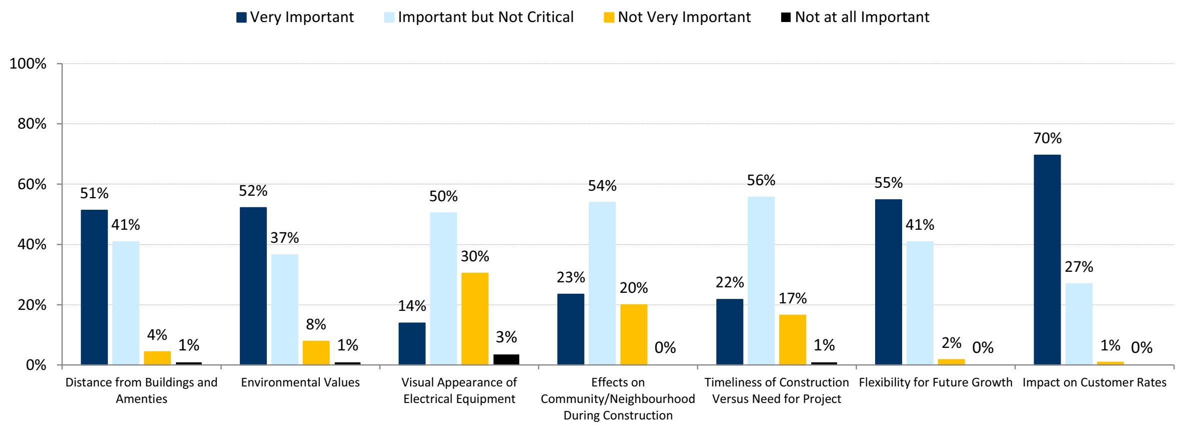
Capital Expenditures

The capital expenditures plan outlines the capital expenditures that FortisBC plans to make in 2012-2013, including sustaining and growth capital requirements for the generation, transmission and distribution plant as well as expenditures related to general utility operations.

Factors in the Capital Expenditures Decision Process

When determining capital expenditures customers would like FortisBC to first consider the impact on customer rates. The visual appearance of equipment is not viewed as highly important or critical.

Importance of Factors to Consider in the Capital Expenditures Decision Process (Total Respondents)

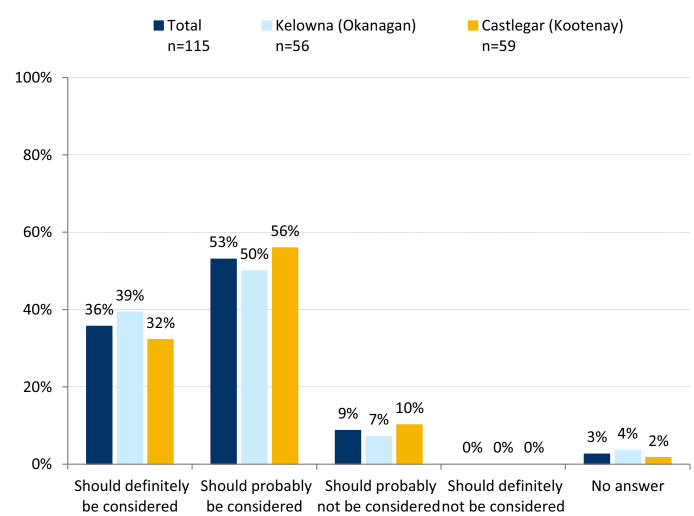


***Please note results may not round to 100% as "don't know" and "no answer" are not reported.**

Social and Environmental Components

Customers support including social and environmental components when capital projects are undertaken.

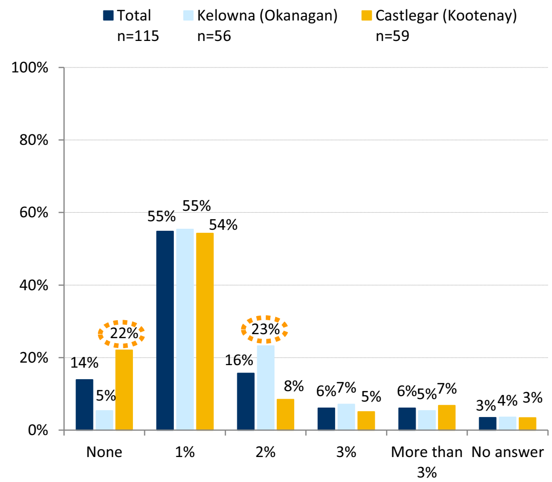
Agreement that FortisBC Should Consider Social and Environmental Components when Capital Projects are Undertaken



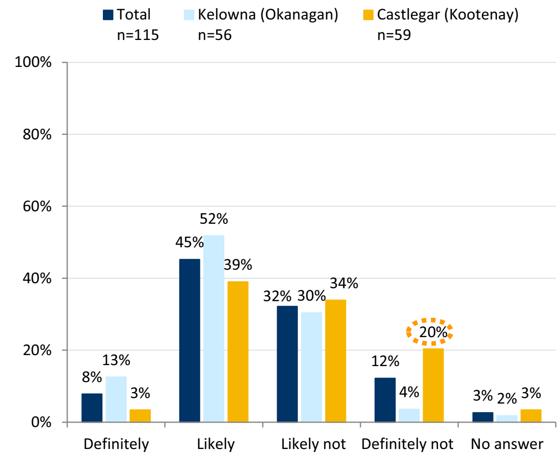
Social and Environmental Components

Although 89% of customers state social and environmental components should definitely or probably be included in the project budget, only about half (53%) are willing pay a higher price for electricity to support it. A reasonable addition to the budget is 1%.

Percentage that is Reasonable to add to Budget for Social and Environmental Components



Willing to Pay a Higher Price to Include Social and Environmental Components



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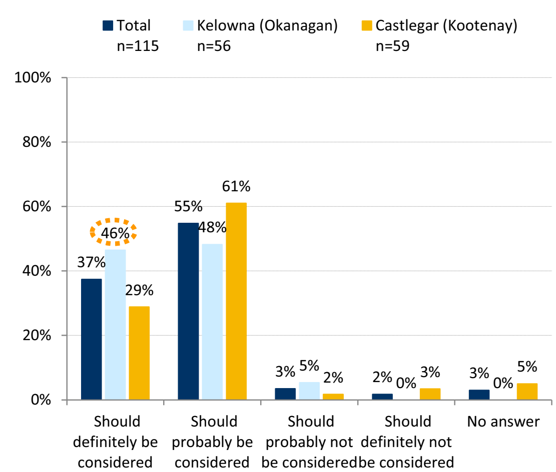
Condition-Based Infrastructure Management

Condition-based management is viewed as an approach that should be considered. There are few people against the switch from time-based management to condition-based management.

Agreement that FortisBC Should Consider Switching from Time-Based Management to Condition-Based Management



Indicates significant regional differences at a 95% confidence level

Condition-Based Infrastructure Management

The switch to condition-based infrastructure management is supported by customers primarily because it is seen as a means to reducing costs.

Reason for Why Condition-Based Infrastructure Management Should or Should Not be Considered

Total Mentions	Total	Kelowna (Okanagan)	Castlegar (Kootenay)
NET: Should be Considered	**n=87**	**n=48**	**n=39**
Lower cost/to keep costs down/controlled costs/could result in cost-savings/will cost less in the long term	37%	38%	36%
Work based on need/fix as needed/when necessary/when the need arises action must be taken	23%	25%	21%
Common sense/it just makes sense	7%	6%	8%
Will conserve energy/less wasted energy/reduce peak usage/(reduced impact on environment)	7%	8%	5%
Avoids wasting time/reduce unnecessary times/eliminates the problems of time	6%	6%	5%
May extend use/may get more use (longer life) out of equipment if keep using until no longer able	6%	6%	5%
Miscellaneous single mentions	6%	4%	8%
Better/increased reliability/more reliable measure	5%	6%	3%
Good/better control/management/more accurately addresses the situation	5%	4%	5%
Cost to consumers is all that matters/cost for such projects should not be passed on to consumer	3%	2%	5%
More efficient way of maintaining infrastructure	3%	0%	8%
More predictable/would lessen the surprise factor/being proactive instead of reactive/knowing in advance about the condition of infrastructure	3%	6%	0%
Not enough information/need more information to make a decision	3%	6%	0%
There would only be a cost-savings with condition-based maintenance if labour costs were reduced/no definite relationship between condition-based maintenance and cost-savings/important to consider total cost for future maintenance at the outset	3%	4%	3%
Will help educate customers about their energy use/be more conscious of their energy consumption	3%	2%	5%
NET: Should Not be Considered	**n=6**	**n=3**	**n=3**
The economy is not able to support the change at this time/poor timing in today's economy	*	*	*
Better/increased reliability/more reliable measure	*	*	*
I would not like to be ordered when to do what/should not be told when I can use dryer or eat supper	*	*	*
Miscellaneous single mentions	*	*	*
Don't know/not stated	*	*	*

***Please note only mentions of 3% or greater are reported due to the wide variety of comments provided.**

***Please note results for "NET: Should Not be Considered" were not provided as base sizes were smaller than n=15.**

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Demand Side Management

Is the planning and implementation of programs designed to modify energy consumption on the customer's side of the meter by encouraging customers to improve energy efficiency, reduce electricity use, change the time of use, or use a different energy source.

Energy Efficiency and Conservation Programs

Customers would like FortisBC to provide general education or information about how to reduce energy consumption.

Desired Energy Efficiency and Conservation Programs

Total Mentions	Total n=80	Kelowna (Okanagan) n=40	Castlegar (Kootenay) n=40
Education/information to consumers/educating the public on how to reduce consumption	13%	5%	20%
Rebates/incentive for customers (non-specific)	9%	8%	10%
Solar incentives/solar water heater rebates/more information on solar panels	8%	3%	13%
Lighting/LED lights/incentives to change to more energy-efficient lighting	8%	10%	5%
Educating our children/energy conservation education programs in schools/information to kids	8%	10%	5%
Upgrading meters to better monitor usage/two-way metering/new metering/Smart Meters/free new meters	6%	8%	5%
Rebates to help out heating expenses/would like to know ways to cut down on heating	6%	8%	5%
Wind power/consider using wind for energy	4%	5%	3%
The program they have now is good/keep going/you're doing a good job	4%	3%	5%
Rebates on appliance upgrades/energy star appliances	4%	3%	5%
Programs that would assist customers to become more energy-efficient/energy-efficiency	4%	5%	3%
New building energy efficiency/more on home renovations/rebates on home upgrades	4%	5%	3%
Get office buildings/large facilities to turn the lights out/get industrial and municipal lighting to shut off when not needed	4%	5%	3%
Alternative energy generation/possible alternative power sources	4%	5%	3%
Would like one bill/one bill for Terason and FortisBC	3%	3%	3%
We do not have natural gas here and must use expensive propane/I use propane but would like to be able to use natural gas	3%	3%	3%
Other devices to help reduce energy consumption/smart power bars that turn off/smart home units where you can operate by telephone control	3%	5%	0%
Helping families to replace old hot water tanks/more efficient hot water tanks	3%	5%	0%
Heat pumps/heat pump installations	3%	3%	3%
Education/information to businesses	3%	5%	0%
Miscellaneous single mentions	20%	23%	18%
Nothing	4%	3%	5%
Don't know/not stated	9%	5%	13%

Energy Efficiency and Conservation Programs

Residential customers would like information on how to reduce consumption while businesses are significantly more likely to mention lighting rebates.

Desired Energy Efficiency and Conservation Programs (Total Mentions)

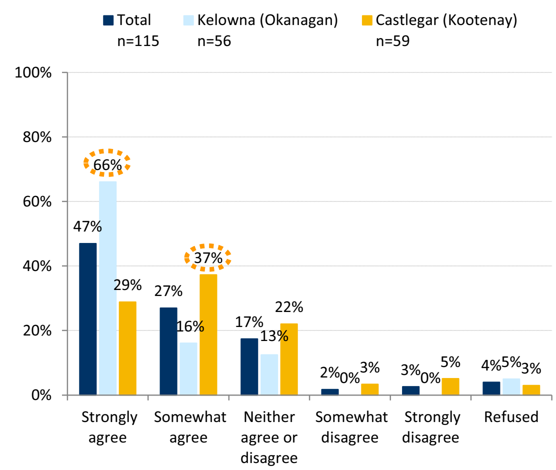
	Total n=80	Residential n=54	Business n=24
Education/information to consumers/educating the public on how to reduce consumption	13%	17%	4%
Rebates/incentive for customers (non-specific)	9%	7%	13%
Lighting/LED lights/incentives to change to more energy-efficient lighting	8%	2%	21%
Solar incentives/solar water heater rebates/more information on solar panels	8%	6%	13%
Educating our children/energy conservation education programs in schools/information to kids	8%	9%	4%
Rebates to help out heating expenses/would like to know ways to cut down on heating expenses	6%	4%	13%
Upgrading meters to better monitor usage/two-way metering/new metering/Smart Meters/free new meters	6%	7%	4%
Alternative energy generation/possible alternative power sources	4%	2%	4%
Get office buildings/large facilities to turn the lights out/get industrial and municipal lighting to shut off when not needed	4%	2%	8%
New building energy efficiency/more on home renovations/rebates on home upgrades	4%	6%	0%
Programs that would assist customers to become more energy-efficient/energy-efficiency programs	4%	4%	4%
Rebates on appliance upgrades/energy star appliances	4%	4%	4%
The program they have now is good/keep going/you're doing a good job	4%	6%	0%
Miscellaneous single mentions	20%	17%	21%
Nothing	4%	4%	4%
Don't know/not stated	9%	7%	13%

Indicates significant regional differences at a 95% confidence level

Joint Conservation Programs Between FortisBC and Terasen Gas

Support for joint conservation programs between FortisBC and Terasen Gas is good. The Okanagan region is more supportive.

Support for FortisBC Considering Joint Energy Conservation Programs with Terasen Gas



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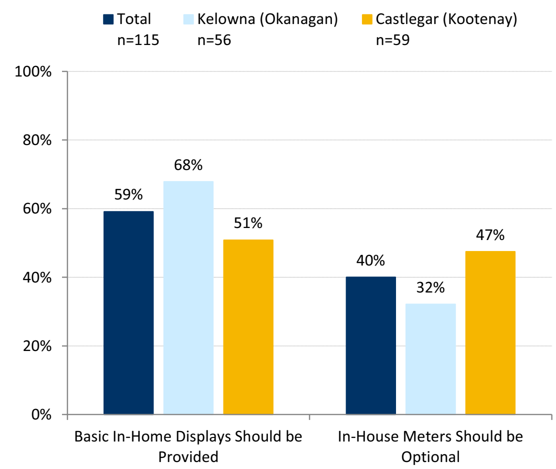
Advanced Metering Infrastructure (AMI)

The Advanced Metering Infrastructure (AMI) project involves replacing the current, manually read meters with advanced meters that can transmit meter reading data directly to FortisBC.

Advanced Metering Infrastructure (AMI)

Two-thirds of Okanagan residents would like in-house displays provided as part of the AMI project, while Kootenay residents are equally split between having in-house displays provided as part of the project or as an optional purchase.

Support for In-House Displays as Part of the AMI Project Versus an Optional Purchase



***Please note results may not round to 100% as "no answer" is not reported.**

Advanced Metering Infrastructure (AMI)

Support for implementing in-house displays across the entire customer base relates to customer interest in education, information, and awareness of energy usage. 18% of people mention cost implications.

Reason for Preferred Option – Basic In-House Displays Should be Provided

Total Mentions	Total n=67	Kelowna (Okanagan) n=38	Castlegar (Kootenay) n=29
Smart Meters help to educate/inform customers/increases awareness of energy use	37%	37%	38%
Customers will be more responsible/mindful of their energy consumption/good for energy conservation	21%	32%	7%
Provide it free of charge/having to buy them would be a disincentive/a lot of people would not want to pay out of pocket for it	18%	13%	24%
Everyone should participate/would be more effective if everyone had one/if not everyone participates there would be no benefit	16%	26%	3%
Excellent idea/really like it/beneficial/I would want it	7%	5%	10%
Helps Fortis keep costs down/overall cost for Fortis would be cheaper/it benefits Fortis	7%	5%	10%
Other cost mentions (ie. Some cost increase can be justified, if everyone is included the cost per customer is lower, less cost if they are provided without a 3rd party, if I have to have it I would want to get the most for my rate increase)	6%	8%	3%
Facility of implementation/use	6%	11%	0%
The whole family could participate/the kids too/will also teach the kids	6%	11%	0%
No access to computer/not a big user of internet/some cannot operate a computer	4%	3%	7%
Cheaper for customers/more cost-effective for consumers/will save money on electric bill	3%	3%	3%
It is up to FortisBC to educate people about the value of the meters/people need to be	3%	5%	0%
Should be given the option/freedom of choice/people should have the option to refuse	3%	3%	3%
Accessing through website would be more cost-effective	1%	3%	0%
If people have it they will use it	1%	3%	0%
Internet is better/preferred/easily accessible	1%	3%	0%
Miscellaneous single mentions	15%	11%	21%

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Advanced Metering Infrastructure (AMI)

Freedom of choice, cost implications and a lack of engagement in monitoring personal energy usage are the primary reasons stated for preferring optional in-house displays.

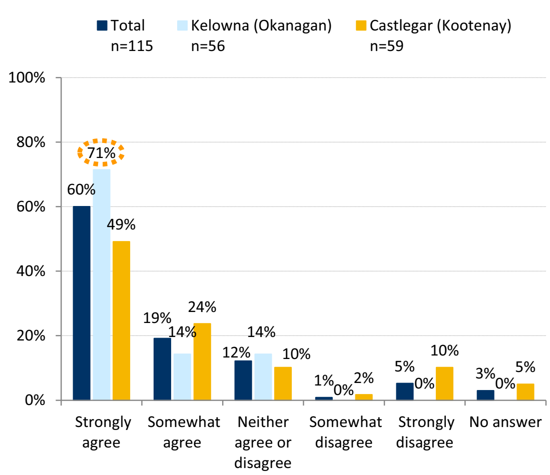
Reason for Preferred Option – In-House Displays Should be Optional

Total Mentions	Total n=41	Kelowna (Okanagan) n=15	Castlegar (Kootenay) n=26
Should be given the option/freedom of choice/people should have the option to refuse	27%	27%	27%
Provide it free of charge/having to buy them would be a disincentive/a lot of people would not want to pay out of pocket for it	20%	27%	15%
Not a critical issue/doesn't matter to me/wouldn't change my energy consumption/I can regulate my own energy use/it is already obvious when we use energy	17%	0%	27%
Internet is better/preferred/easily accessible	15%	27%	8%
People will get tired of looking at it/would just be a novelty at the beginning/would look at it initially and forget about it over time	10%	20%	4%
Cheaper for customers/more cost-effective for consumers/will save money on electric bill	7%	0%	12%
No access to computer/not a big user of internet/some cannot operate a computer	7%	20%	0%
Those who want it should pay for it	7%	13%	4%
Benefits don't outweigh the costs	5%	7%	4%
Don't want it/against them	5%	0%	8%
Excellent idea/really like it/beneficial/I would want it	5%	0%	8%
Expensive venture if no one uses it/it is money Fortis could have saved	5%	0%	8%
Internet is more comprehensive/better more usable information online	5%	7%	4%
Accessing through website would be more cost-effective	2%	7%	0%
Helps Fortis keep costs down/overall cost for Fortis would be cheaper/it benefits Fortis	2%	7%	0%
If people have it they will use it	2%	0%	4%
It is up to FortisBC to educate people about the value of the meters/people need to be educated about the program	2%	0%	4%
Smart Meters help to educate/inform customers/increases awareness of energy use	2%	0%	4%
Miscellaneous single mentions	2%	7%	0%

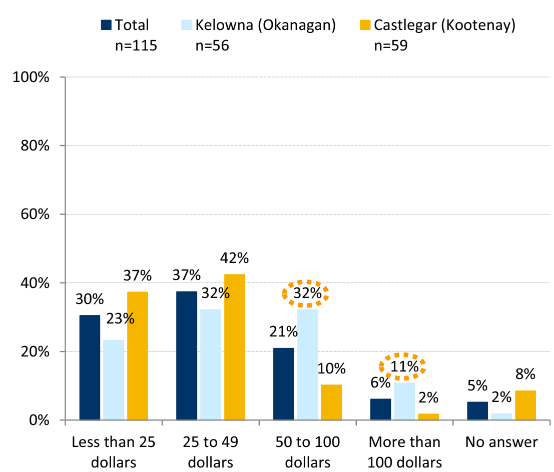
Advanced Metering Infrastructure (AMI)

If in-house displays were optional, customers would like to see an incentive program with these purchases. Most customers would pay up to 50 dollars for an in-house display.

Customer Support for an In-House Display Purchase Incentive Program (If an Optional Component of AMI)



Customer Price Point for Optional In-House Display



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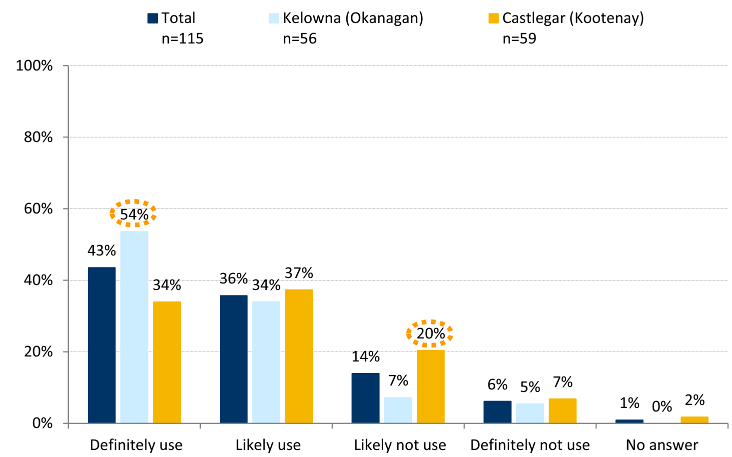
Advanced Metering Infrastructure (AMI)

When AMI is introduced, the majority of customers will use the FortisBC website provided for tracking their energy usage.

Likelihood that Customers Will Use a Secure Website to Track Energy Usage



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Advanced Metering Infrastructure (AMI)

The FortisBC website is a popular idea for customers so they can easily track usage or spot times of high usage. Issues with a website only approach is that some customers don't have access to a computer or are not computer literate.

Reasons Why a Secure Website Would or Would not be Used

Total Mentions	Total	Kelowna (Okanagan)	Castlegar (Kootenay)
Net: Would use (definitely/likely)	**n=89**	**n=48**	**n=41**
I am interested in my usage/tracking my usage/spotting my high usage times	30%	29%	32%
Would help with energy conservation/would use less/would help me make smart choices on power use/change the times of day I would use it	26%	33%	17%
Interested in where I can save money/helps me to manage the bill/it will keep the cost lower	16%	19%	12%
To become more informed/get more information/details	8%	10%	5%
Would only look at it periodically/not often/not on a regular basis	8%	8%	7%
Just to see/out of curiosity/interesting	7%	6%	7%
We use the internet extensively/always on the computer anyway/already pay bills online	6%	8%	2%
Prefer to use in-home display/home display meter would be enough	6%	4%	7%
Want to know the energy-draw of certain appliances/what it is costing me for each appliance	4%	4%	5%
Good/convenient access	4%	4%	5%
Other specific convenience mentions (ie. Can view information at my leisure, easy way, most efficient way, more flexible)	4%	8%	0%
Wonder how much this would cost/as long as there are no new charges for this	4%	2%	7%
Miscellaneous single mentions	8%	6%	10%
Net: Not use (likely not/definitely not)	**n=21**	**n=5**	**n=16**
Don't have access to a computer	19%	40%	13%
Not computer literate/don't know how to operate a computer very well	19%	0%	25%
Won't affect my power usage	14%	0%	19%
Don't like my personal information online	10%	0%	13%
Don't use the computer much/don't like using the computer	10%	0%	13%
Would help with energy conservation/would use less/would help me make smart choices on power use/change the times of day I would use it	10%	20%	6%
Wonder how much this would cost/as long as there are no new charges for this	5%	20%	0%
Don't have a lot of time to go online	5%	0%	6%
Prefer to use in-home display/home display meter would be enough	5%	20%	0%
Miscellaneous single mentions	10%	0%	13%

***Please note only mentions of 4% or greater are reported due to the wide variety of comments provided.**

Advanced Metering Infrastructure (AMI)

Positive support for the AMI program is a function of customer interest in energy usage or conservation (implied). Customers who are neutral about the program require additional information to make an informed choice. Cost remains a concern.

Comments About Advanced Metering or Smart Meter Programs

Total Mentions	Total n=93	Kelowna (Okanagan) n=49	Castlegar (Kootenay) n=44
Net: Positive	**46%**	**53%**	**39%**
Sounds good/fine/positive/I support it/the right direction/excellent project	33%	41%	25%
Will help people understand their usage/tool to keep people informed of their energy	9%	8%	9%
It is smart/smart investment/smart people use Smart Meters	3%	6%	0%
Will have a significant impact on usage/would reduce people's energy use	3%	2%	5%
More control over my power bill	2%	0%	5%
Would mean savings/savings in the long run	2%	2%	2%
Good idea to change the price depending on the peak period/there should be two prices for peak and non-peak times	3%	6%	0%
Net: Neutral	**27%**	**31%**	**23%**
Never heard of this before	11%	12%	9%
Would like more information/customers need to be enlightened and informed	9%	8%	9%
Good as long as it doesn't cost more/too much	3%	2%	5%
Puts the responsibility on the consumers	3%	6%	0%
A double-edged sword/good but have concerns	2%	2%	2%
Net: Negative	**15%**	**2%**	**30%**
Makes billing more expensive/concerned about increased costs/rates	8%	2%	14%
Not needed/should be optional/our usage wouldn't change/I am smarter than the meter	4%	0%	9%
They will charge us more during peak periods/worry about variable time-based rates	5%	0%	11%
Totally against it/they should be axed	2%	0%	5%
Miscellaneous single mentions	15%	18%	11%
Nothing	10%	10%	9%

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Advanced Metering Infrastructure (AMI)

Customers would like to understand the additional costs of AMI before the program is introduced into their community.

Additional Information Desired About Advanced Metering Infrastructure

Total Mentions	Total n=83	Kelowna (Okanagan) n=43	Castlegar (Kootenay) n=40
Cost/associated costs/rates/what is the real cost to me?/how will it affect my bill?	35%	37%	33%
How this will benefit me/how it benefits consumers	8%	9%	8%
Do not change rates for high demand times/would like a guarantee that prices won't go up during peak usage times/do not raise rates	6%	2%	10%
How to use the information properly/how to understand what you are looking at/how to read the metering differences	5%	7%	3%
Installation schedule/implementation date/when we can get one	5%	7%	3%
Educate people in ways to save power/more information on conserving energy	4%	0%	8%
Have information meetings for the public/training/workshops	4%	2%	5%
How it works/operates	4%	5%	3%
More information (non-specific)	4%	5%	3%
More information on energy efficient appliances and devices/timer-based	4%	5%	3%
Pros and cons	4%	5%	3%
How accurate it will be/would living under hydro lines impact the digital readouts?	2%	2%	3%
How much time involved?/any downtime for changes to take place?	2%	5%	0%
Incentives to not use power during peak demand times	2%	5%	0%
The big picture advantage/how it will benefit the environment	2%	2%	3%
Miscellaneous single mentions	8%	9%	8%
Nothing	13%	12%	15%
Don't know/not stated	6%	5%	8%

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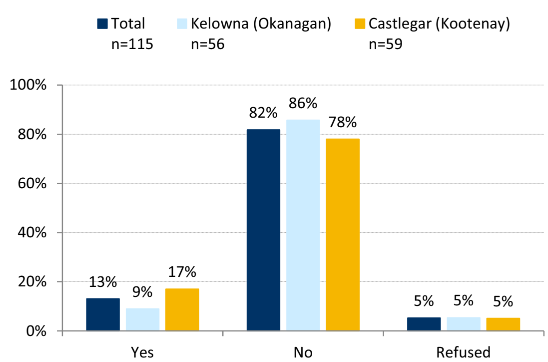
Communications

Communications/Information on the ISP

Super Group participants in both locations identified that the ISP presentation was neither confusing or difficult to understand. A few customers would like to better understand the business model of FortisBC (i.e., where profits are used).

Customer Opinions on Whether the Informational Presentation on the ISP Had Confusing or Difficult Parts to Understand



	Total n=115	Residential n=81	Business n=32
Yes	13%	17%	3%
No	82%	81%	81%
No answer	5%	1%	16%

What Customers Found Confusing or Difficult to Understand about the ISP Presentation

	Total n=15
The idea that it is not for profit/that Fortis doesn't make money by selling power?/then where do all the profits go?	20%
Was not sure what this was about/not familiar with these things so it was confusing	13%
Understanding the purchasing of power/complex nature of power purchasing and storing	13%
Future of the Smart Meters/Smart Metering vs. advanced metering	13%
Current and future rate increases	7%
Sound system was bad/poor mic setup/couldn't hear	7%
Miscellaneous single mentions	13%
Refused/No answer	13%

***Please note regional differences were not provided as base sizes were smaller than n=15.**

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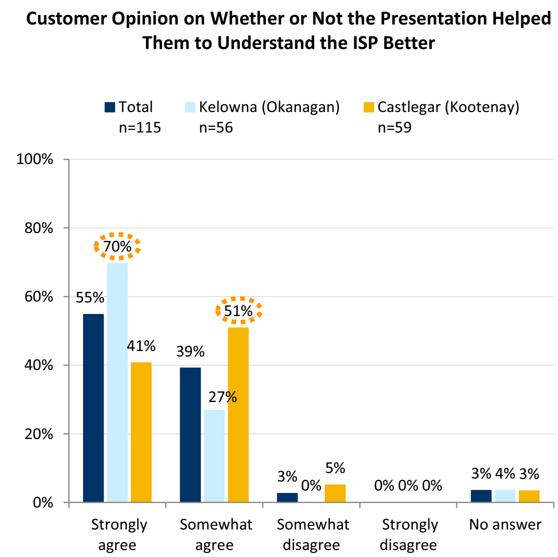
Communications/Information on the ISP

Overall, the ISP presentation was informative and helped customers to understand the ISP better.



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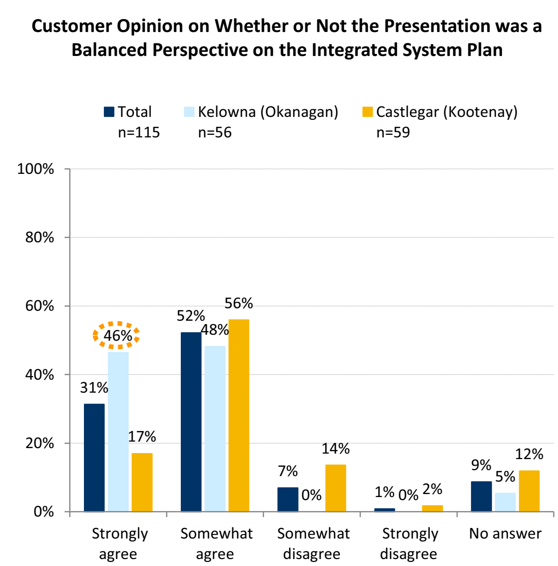
Communications/Information on the ISP

83% of participants strongly or somewhat agree the presentation presented a balanced perspective.



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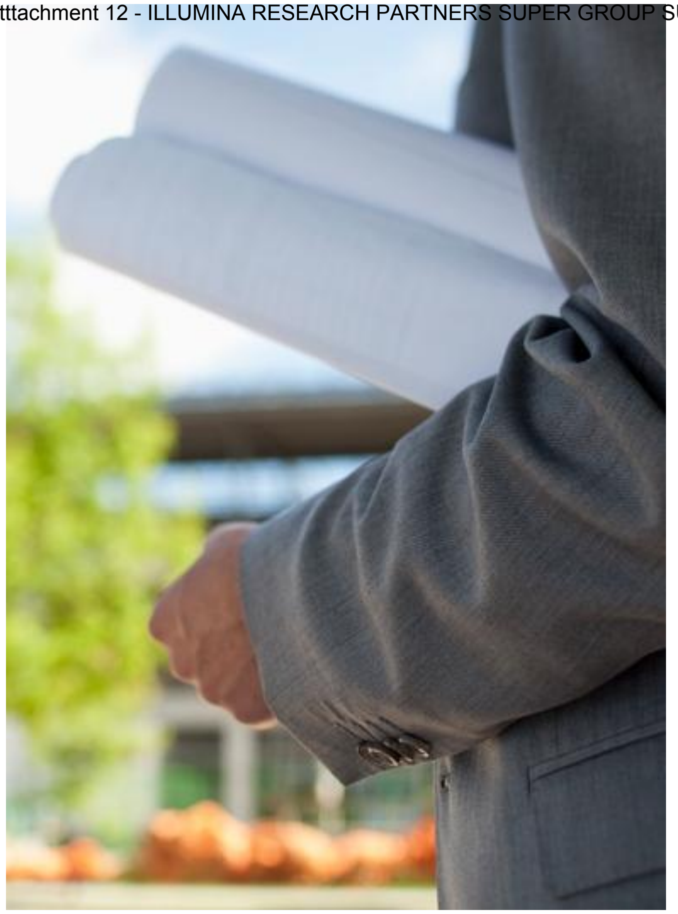
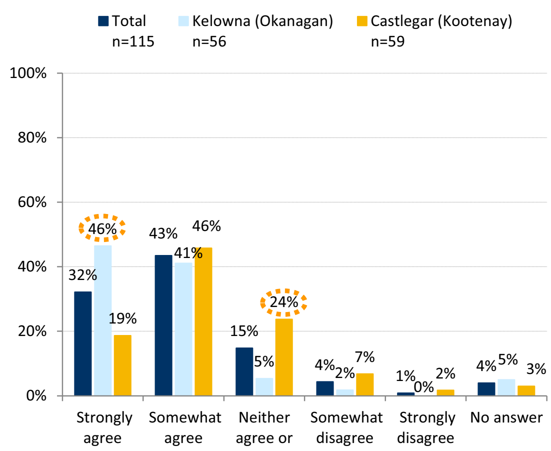


Overall Perception of the Integrated System Plan

Overall Perceptions of the ISP

Most customers are agree that the Integrated System Plan is fulfilling the objective of setting out a five year plan towards meeting the energy needs of the next 20 to 30 years. Kootenay residents are less positive overall about the ISP compared to Okanagan residents.

Customer Opinion on Whether or Not the Integrated System Plan Fulfills FortisBC's Objective of Planning for the Next 20 to 30 Years



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Overall Perceptions of the ISP

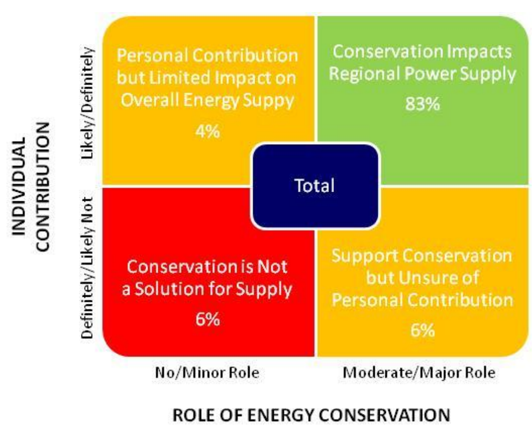
Okanagan participants enjoyed the presentation while Kootenay participants have concerns about costs and rate increases.

Additional Thoughts and Comments

Total Mentions	Total n=62	Kelowna (Okanagan) n=36	Castlegar (Kootenay) n=26
Net: Positive	**37%**	**53%**	**15%**
Excellent presentation/well done	15%	25%	0%
Fortis is Canadian-owned and operated/good to know that Fortis and Terasen are Canadian-owned	3%	6%	0%
Fortis seems to know what they're doing/doing a good job/making great strides to ensure the advancement of	8%	14%	0%
Informative presentation/learned a lot	18%	28%	4%
Other specific positive presentation mentions (ie. Good display boards, honest and composed presenter, felt like I was part of the team)	3%	3%	4%
Thank you/thanks for the opportunity	13%	14%	12%
Net:Neutral	**31%**	**36%**	**23%**
Would like a discussion on alternate energy methods/nuclear energy/promote solar energy/need new ways to produce	8%	6%	12%
Hold more customer workshops/seminars on energy conservation	6%	6%	8%
Keep educating kids/getting kids involved	6%	11%	0%
Need more public awareness/send out information to people	5%	6%	4%
Strongly encourage conservation/promote energy-saving products and practices/there is a lot more customers could do to conserve energy	5%	6%	4%
Provide incentives/rebates to help customers conserve energy	3%	6%	0%
Net:Negative	**24%**	**11%**	**42%**
Too many rate increases/too excessive/where will all the increases leave us?	10%	6%	15%
Other cost mentions (ie. Altogether costs too much, only above a certain basic amount should be at a cost to consumers, worry about cost increase in relation to Waneta expansion, people should expect energy costs to go up and not complain about it, approve of the methods planned to keep costs down)	8%	3%	15%
Don't want to see any excess energy sold out of country/want to know why power was sold to U.S./control where the power goes	5%	3%	8%
Negative presentation mentions (ie. Give us actual dollar figures so it makes more sense, rates should have been noted	3%	3%	4%
Miscellaneous single mentions	18%	22%	12%
Nothing	6%	0%	15%

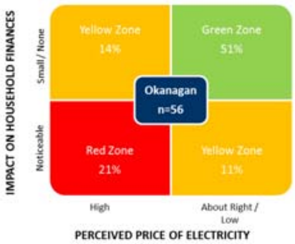
Residential customers were more likely than business customers to provide negative comments about the ISP (25% versus 6% respectively). While both groups were concerned with possible rate increases/costs, only Residential were concerned with selling energy outside BC or the content of the presentation.

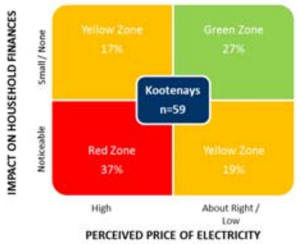
Indicates significant regional differences at a 95% confidence level



Appendix 1: How to Read 2X2 Charts.

How to Read 2X2 Charts





Questions

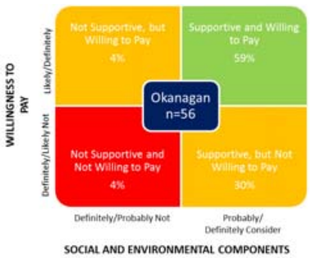
X-Axis: Do you feel the price you currently pay for your household electricity service is:

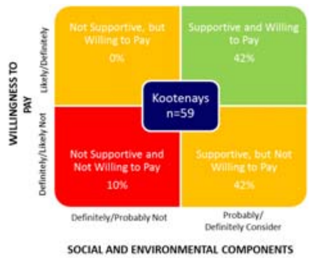
Too low, About right, Too high

AND

Y-Axis: Does the current size of your household electricity bill make a noticeable, small or no impact on your household finances each month?

Noticeable impact, Small impact, No impact





Questions

X-Axis: Customers are telling FortisBC that they want to see additional social and environmental components added when capital projects are undertaken… Please indicate whether you think visual screening, special environmental treatments or other community specific amenities should:

definitely be considered, probably be considered, probably <u>not</u> be considered or definitely <u>not</u> be considered.

AND

Y-Axis: Would you definitely, likely, likely not, or definitely not pay a higher price for the electricity you buy at home in order to include social and environmental components…

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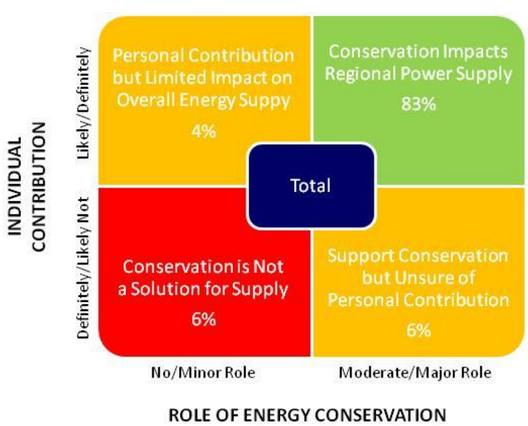
How to Read 2X2 Charts



Questions

X-Axis: Do you think energy conservation can play a major role, a moderate role, a minor role, or no role at all in ensuring the region has the supply of power it will need.

Major role, Moderate role, Minor role, No role at all.

AND

Y-Axis: Do you think that individual consumers such as yourself can definitely, likely, likely not or definitely not make an important contribution to reducing the overall amount of electrical energy used in the region?

Definitely could reduce overall energy use,

Likely could reduce overall energy use,

Likely not reduce overall energy use,

Definitely not reduce overall energy use.

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Appendix 2: Summary of Super Group Question and Answer & Information Booth De-Brief Transcripts

Summary of Question and Answer Transcripts

The Question and Answer session primarily touched on key topics of the ISP presentation. A number of questions were due to the desire for greater information on the topic, especially relating to costs and rate implications.

Transcript Summary – General Topics

Alternative Energy Sources
Time-Based Management and Condition-Based Management
The Waneta Expansion (Costs, Ownership)
Discussion on Buying from External Sources/Selling Power to External Sources (outside BC)
Building of New Generation
Trends in Consumer Conservation/Energy Conservation Incentives/Education about Conservation for Youth/FortisBC Outreach and Education/Education on Energy Efficient Products)
Smart Meter Programs (General Information/Costs/Rates/Costs of In-House Meters/Introduction in Municipalities/Impact on Jobs/Meter Technology/Billing Process/Content of Meter Data)
Incentive Programs/Rebates/Buy Back Programs
Use of Independent Power and Renewables
Peak Power Usage Pricing/Time of Use Rates/Benefit to FortisBC of Time of Use Rate System/Information on Peak Usage Profiles
Herbicide Spraying Program
Net Metering/Customer Generated Power Supply
Usage of Gas Fire Generating Plants
Residential Rate History/Rate Increases/Cause of Rate Increases
FortisBC Profits/Financial Model
FortisBC Contribution or Involvement in the Government Regulation Process

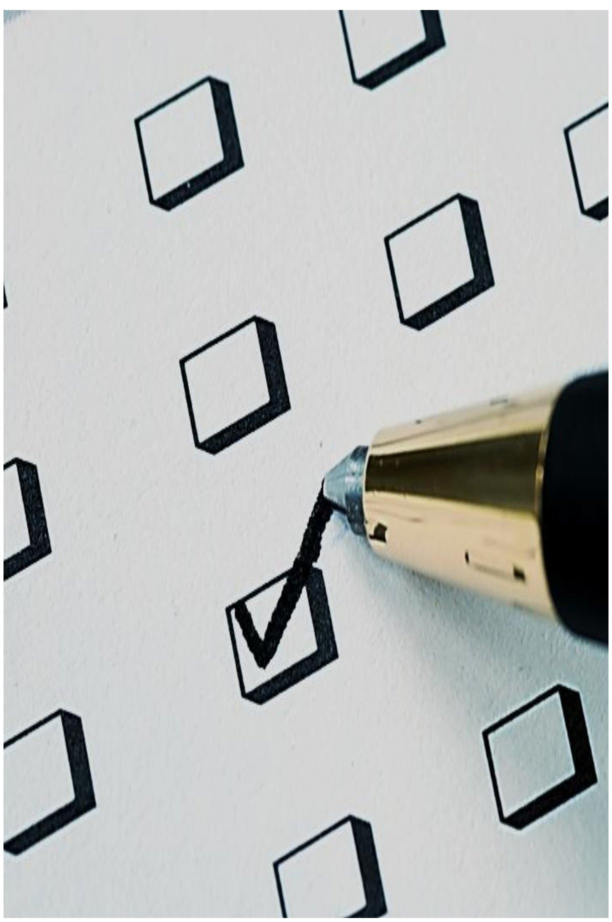
Summary of Information Booth De-Brief Transcripts

A wide variety of topics were discussed/explored at the Information booths. While many questions/comments related to ISP topics, there were also other topic areas of current interest to customers. A list of subject areas is provided below.

Transcript Summary – General Topics

Brownfield and Greenfield construction
Resource Plan (power purchase agreements/Canal Plant Agreements)
EMF (Electric & Magnetic Fields) – Ellison-Sexsmith Transmission Line
Asset Value Definition/Description
Substations/Transmission of Distribution Lines
Delivery Charge for Gas/Cost of Electricity
Growth of Customer Base
Penticton Substation
FortisBC's Susceptibility to Take-Over
3808 negotiations and the PPA Rate
Load Forecasting
BC Hydro IPPs/Clean Call for Power
Differences Between Energy and Capacity
Gas Turbines/Wind Turbines and PowerSense/Pump Storage Hydro
Power Supply Contractual Agreements
Price Upon Renewal
Demand Side Management

Advanced Metering/Smart Metering
Energy Options or Combinations
Conservation/Energy Efficiency Education or Solutions
Peak Period Reduction/Peak Period Pricing
Live Smart Program
Additional Information on the ISP Application
Dam Maintenance/Safety/Security/Operations
Fortis Stocks and Dividend Returns
Planning Reserve Margin
Building Versus Buying for Supply
Bill Impacts/Residential Basic Rates
PowerSense Education/Initiatives
Condition Versus Time-Based Management
Alternative Power Subsidies/Incentives in Other Countries
Rate of Return
Distributed Generation
ISP Benefits



Appendix 3: Screener and Questionnaires

Screener

Respondent

Name:____

Home Phone #____

Business Phone #______________________________________

E-Mail:____

Group #:____________________ **Recruiter:**______________________________

Recruit 70 per group

GROUP 1	GROUP 2
Wednesday	Thursday
February 23rd	FEBRUARY 24TH
7:00 p.m.	7:00 p.m.
KELOWNA	CASTLEGAR

Hello, my name is _________ from XXX., we are calling today to invite you to a market research workshop scheduled for (DATE) in (LOCATION). Your participation in the research is completely voluntary and your decision to participate or not will not affect any dealings you may have with XXX. All information collected, used and/or disclosed will be used for research purposes only and administered as per the requirements of the Privacy Act. You will also be asked to sign a waiver to acknowledge that you may be audio and/or video taped during the session. The session will last a maximum of 2 hours and you will receive a cash honorarium of $75.00 as a thank you for attending the session. May we have your permission to ask you some further questions to see if you fit in our study?

Yes……………………………………1
No……………………………………2 – **THANK AND TERMINATE**

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Screener

Recruiters please note: If the respondent mentions it will take over an hour to get to the hotel please offer them $100.00!
Please ensure quota's below from lists

Customer Class	Customer Count
Residential	(49)
General Service/Commercial	(13)
Industrial Primary/Transmission	(2)
Wholesale	(0)
Lighting	(3)
Irrigation	(3)

INDICATE: Male…………………………………1 ½ PER GROUP
Female……………………………2 ½ PER GROUP

1. Are you or is any member of your household or immediate family employed in, or ever been employed in:

	1		Ever	
	No	Yes	No	Yes
Market Research	( )	( )	( )	( )
Marketing	( )	( )	( )	( )
Public Relations	( )	( )	( )	( )
Any media (Print, Radio, TV)	( )	( )	( )	( )
A member of ACTRA	( )	( )	( )	( )
Advertising	( )	( )	( )	( )
Electricity/hydro	( )	( )	( )	( )

IF YES TO ANY OF THE ABOVE – THANK AND TERMINATE
IF WHOLESALE DO NOT TERMINATE FOR ELECTRICITY/ HYDRO

2a. May I have your age, please?

____________________ SPECIFY

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Screener

Okanagan

18-34 ....1- **RECRUIT 11**
35-59 years....................................2- **RECRUIT 30**
Over 60...3- **RECRUIT 29**

Kootenay

18-34 ....1- **RECRUIT 11**
35-59 years....................................2- **RECRUIT 35**
Over 60 .. ..3- **RECRUIT 24**

2b. What is your marital status?

Married / Common – Law..................1
Single / Div. / Wid. / Sep...................2

3a. What is your current employment status?

Full Time Employed ( )
Part Time Employed ( )
Homemaker ( )
Student ( )
Retired ( )
Unemployed ( )

3b. What is your occupation? –IF RETIRED – ASK PRIOR OCCUPATION

______________________________ JOB TITLE
______________________________TYPE / NAME OF COMPANY

IF MARRIED / COMMON – LAW ASK – WHAT IS YOUR SPOUSE'S OCCUPATION?

______________________________ JOB TITLE
______________________________TYPE / NAME OF COMPANY

Screener

IF ANY CONNECTION TO STANDARD OR PROJECT RELATED OCCUPATION – THANK AND TERMINATE

4a. As we need to speak with people from all walks of life, could you please tell me into which category I may place your total annual household income? Would that be...

Under $40,000....................................1
$40,000 - $60,000...............................2
$60,001 - $80,000...............................3
Over $80,000......................................4

4b. Could you please tell me, what is the last level of education that you have completed?

Some High School..............................1
High School.......................................2
Some College / University.....................3
Completed College / University..............4

5 Who in your household is responsible for paying your hydro/electricity bill?

Self 1
Shared 2
Other ....3 **TERMINATE**

The next couple of questions deal with your imagination. Have a little fun with these questions and feel free to answer in any way, as there are no incorrect answers.

6a. What would be the first thing you would do, if you had just won one million dollars?

____
____
____

Screener

6b. If you were a book in a library, what book would you be and WHY?

____

____

____

__________ ANSWERS SPONTANEOUSLY
__________ VERY ENTHUSICASTIC
__________ VERY SURE OF HIMSLEF / HERSELF
__________ CARRIES ON A GOOD CONVERSATION

NOTE: PAY EXTRA ATTENTION TO RESPONDENT ANSWERS – LOOK FOR COMPLEX, CREATIVE ANSWERS AND NOT JUST MEANINGLESS ANSWERS. LOOK FOR IMAGINATION AND A SENSE OF CREATIVITY / PARTICIPATION.

7. Participants in group discussions are asked to voice their opinions and thoughts, how comfortable are you, in voicing your opinions in front of others? Are you….

Very Comfortable…………………………..1 – **MIN 50% PER GROUP**
Comfortable…………………………………3
Fairly Comfortable…………………………..3
Not Very Comfortable……………………….4 – **THANK AND TERMINATE**
Very Uncomfortable…………………………5 – **THANK AND TERMINATE**

8a. Have you ever attended a focus group or one to one discussion for which you have received a sum of money, here or elsewhere?

Yes…………………………………………….1 – **MAX (50%) PER GROUP**

Screener

No……………………………………………..2 – **SKIP TO Q. 14a**

8b. When did you last attend one of these discussions?

____
TERMINATE IF IN THE PAST 6 MONTHS

8c. How many focus group or one –to-one discussions have you attended in the past 5 years?

____
(SPECIFY) IF MORE THAN 5 – THANK AND TERMINATE

8d. Would you please tell me the topics discussed?

____

____

IF Hydro- THANK AND TERMINATE

9. Have you yourself lived in B.C.:

Less than 1 years …………………………1 – **THANK AND TERMINATE**
Between 1 – 5 years……………………….2
More than 5 years………………………….3

10. Have you been invited to another of these focus groups or interviews in the near future?

Yes……………………………………..1 – **THANK AND TERMINATE**
No……………………………………….2

11. Sometimes participants are asked to write out their answers on a questionnaire or watch a TV commercial during the discussion. Is there any reason why you could not participate?

Screener

Yes………………………………………..1 – **THANK AND TERMINATE**
No…………………………………………..2

NOTE: IF RESPONDENT OFFERS ANY REASON SUCH AS SIGHT OR HEARING PROBLEM, A WRITTEN OR VERBAL LANGUAGE PROBLEM, A CONCERN WITH NOT BEING ABLE TO COMMUNICATE EFFECTIVELY – THANK AND TERMINATE

INCENTIVE: $75.00

IMPORTANT:
The session is 2 hours in length, but we are asking that all participants arrive 10 minutes prior to the start time of the session. Are you able to be at the research facility 10 minutes prior to the session time?

Yes…….1
No……..2 – TERMINATE

All participants in this study are asked to bring to the group PICTURE IDENTIFICATION. If you do not bring your personal identification then you will not be able to participate in the session and you will not receive the incentive fee. Are you going to bring along your ID?

Yes…….1
No……..2 – TERMINATE

I would like to invite you to a group discussion on:

GROUP 1	GROUP 2
Wednesday	Thursday
February 23rd,	FEBRUARY 24TH
7:00 p.m.	7:00 p.m.
KELOWNA	CASTLEGAR

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Screener

The workshop will last approximately 2 hours and we offer each participant a $75.00 Cash gift as a token of our appreciation. I should also tell you that the groups will be audio - taped for research purposes and members of the research team will be observing the discussion. Everything you say will be kept confidential.
[ ] CHECK TO INDICATE YOU HAVE READ THE STATEMENT TO THE RESPONDENT.
Recruiters please note: If the respondent mentions it will take over an hour to get to the hotel please offer them $100.00!

Incentive offered $75.00 ( ) $100.00 ( )

Wednesday February 23rd

Kelowna, BC
Fairfield by Marriott
Okanagan Room
1655 Powick Road, Kelowna
Tel: 250-763-2800

Thursday February 24th

Castlegar, BC
Sandman Hotel
Kootenay Room
1944 Columbia Ave, Castlegar
Tel: 250-365-8444

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Questionnaire – Part 1

Electrical Questionnaire

Part 1
Background Information

INSTRUCTIONS

- You have 15 minutes to complete this section
- When you are done this section, please put your pencil down
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

FORTISBC

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Questionnaire – Part 1

1. Which of the following describes your electricity account(s) with FortisBC? *Check all that apply*
   Residential ☐ Industrial Primary / Transmission ☐
   General Service / Commercial ☐ Lighting ☐
   Irrigation ☐

2. Please write in your age: ______

3. Please indicate your gender: Male ☐ Female ☐

4. Please record your postal code: __ __ __ __ __ __

5. Which of the following best describes your own present employment status? *Check one box only*
   Working full-time ☐ Stay at home full-time ☐
   Working part-time ☐ Student ☐
   Unemployed or looking for a job ☐ Retired ☐

6. Do you currently own or rent your home? *Check one box only*
   Own ☐ Rent ☐

7. Which of the following best describes your home? *Check one box only*
   Single detached house ☐ Mobile home ☐
   Townhome or duplex ☐ Basement Suite / Suite ☐
   Apartment building ☐ Other ☐

8. What is the square footage of your home?
   Less than 800 sq. ft. ☐ 1,600 to less than 2,000 sq. ft. ☐
   800 to less than 1,200 sq. ft. ☐ 2,000 to less than 2,500 sq. ft. ☐
   1,200 to less than 1,600 sq. ft. ☐ More than 2,500 sq. ft. ☐

9. What fuel do you use to heat your home?
   Natural Gas ☐ Electricity ☐
   Oil ☐ Wood ☐
   Propane ☐ Other________________ ☐
   Please Specify

10. Please indicate the main heating system you use in your home. *Check one box only*
    Central air ☐ Heat pump (air or ground) ☐
    Electric baseboards ☐ Wood, gas or electric fireplace ☐
    Hot water baseboards / radiator ☐ Other________________ ☐
    Please Specify

11. Do you have air conditioning in your home?
    Yes, central air ☐ Yes, a window unit ☐ No ☐

12. How many people, including yourself, currently live in your household? ______ people

13. Do you feel the price you currently pay for your household electricity service is:
    Too low ☐ About right ☐ Too high ☐

14. Does the current size of your household electricity bill make a noticeable, small or no impact on your household finances each month? *Check one box only*
    Noticeable impact ☐ Small impact ☐ No impact ☐

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Questionnaire – Part 1

15. I would now like to ask you about your region's supply of electrical energy; which includes the energy generated by hydro-electric dams or purchased through the open market that is then distributed by sub-stations to homes and businesses. From what you know or have heard, do you think the region currently has more than enough, as much as is needed, or less than is needed, to meet the region's demand for electrical power over the next two to five years?
More than enough ☐ As much as needed ☐ Less than needed ☐

16. And what about the longer term? Do you think your region will have more than enough, as much as needed, or less than is needed to meet the electrical power demand 20 years from now?
More than enough ☐ As much as needed ☐ Less than needed ☐

17. One way to address the electrical power needs of the region is through energy conservation, which can be defined as making conscious decisions and actions to reduce your use of energy, which might involve being more efficient or cutting back the amount of energy used.
Do you think energy conservation can play a major role, a moderate role, a minor role, or no role at all in ensuring the region has the supply of power it will need? *Check one box only*
Major role ☐ Minor role ☐
Moderate role ☐ No role at all ☐

18. Do you think that individual customers such as yourself can definitely, likely, likely not, or definitely not make an important contribution to reducing the overall amount of electrical energy used in the region?
Definitely could reduce overall energy use ☐
Likely could reduce overall energy use ☐
Likely not reduce overall energy use ☐
Definitely not reduce overall energy use ☐

19. FortisBC, your electricity supplier, is currently developing a comprehensive plan that looks ahead 20 to 30 years to identify the energy and infrastructure needs of customers and which is used to develop a five year business plan which will meet these future energy and infrastructure needs.
Have you heard of the FortisBC Integrated System Plan before today?
Yes ☐ No ☐ Don't know ☐

20. There are a number of challenges to consider when planning for future energy and infrastructure needs. Please identify for each of the following challenges whether it is critically important, important but not critical, not very important, or not at all important for FortisBC to address the challenge of note.

	Critically important	Important but not critical	Not very important	Not at all important	Don't know
Minimizing the environmental impacts of electrical infrastructure and equipment	☐	☐	☐	☐	☐
Keeping down the cost/managing the future cost of electricity charged to customers	☐	☐	☐	☐	☐
Ensuring a reliable source of power	☐	☐	☐	☐	☐
Generating power within BC rather than importing it from outside BC	☐	☐	☐	☐	☐
Conserving/reducing our energy consumption	☐	☐	☐	☐	☐
Meeting the goals of the BC Energy Plan	☐	☐	☐	☐	☐
Meeting the goals of the BC Clean Energy Act	☐	☐	☐	☐	☐
Minimizing power outages	☐	☐	☐	☐	☐
Minimizing the visual impacts of electrical infrastructure and equipment	☐	☐	☐	☐	☐
Helping customers understand how to manage their energy consumption	☐	☐	☐	☐	☐

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Questionnaire – Part 1

21. Are there any other challenges that FortisBC has not identified?

22. Among the challenges you identified as critically important to address, which ONE do you think is the most important of all?
Minimizing the environmental impacts of electrical infrastructure and equipment ☐
Keeping down the cost/managing the future cost of electricity charged to customers ☐
Ensuring a reliable source of power ☐
Generating power within BC rather than importing it from outside BC ☐
Conserving/reducing our energy consumption ☐
Meeting the goals of the BC Energy Plan ☐
Meeting the goals of the BC Clean Energy Act ☐
Minimizing power outages ☐
Minimizing the visual impacts of electrical infrastructure and equipment ☐
Helping customers understand how to manage their energy consumption ☐

23. Why do you say that? __________

24. Have you heard of any energy efficiency rebates or programs offered by FortisBC's PowerSense Program?
Yes ☐ No ☐

25. If you answered **YES** to the previous question, what PowerSense rebates or programs are you aware of?

When you are done, please put your pencil down and wait for the facilitator to provide further instructions.

FORTISBC

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Questionnaire – Part 2

Electrical Questionnaire

Part 2

Customer Opinion on ISP Action Items

INSTRUCTIONS

- You have 15 minutes to complete this section
- When you are done this section, please put your pencil down
- When everyone is ready, the facilitator will provide further instructions
- Please don't disturb your neighbours (Thank you!)

FORTISBC

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Questionnaire – Part 2

1. Now that FortisBC has reviewed the Integrated System Plan with you, please identify for each of the following challenges that you rated earlier, whether it is critically important, important but not critical, not very important, or not at all important for FortisBC to address the challenge of note.

	Critically important	Important but not critical	Not very important	Not at all important	Don't know
Minimizing the environmental impacts of electrical infrastructure and equipment	☐	☐	☐	☐	☐
Keeping down the cost/managing the future cost of electricity charged to customers	☐	☐	☐	☐	☐
Ensuring a reliable source of power	☐	☐	☐	☐	☐
Generating power within BC rather than importing it from outside BC	☐	☐	☐	☐	☐
Conserving/reducing our energy consumption	☐	☐	☐	☐	☐
Meeting the goals of the BC Energy Plan	☐	☐	☐	☐	☐
Meeting the goals of the BC Clean Energy Act	☐	☐	☐	☐	☐
Minimizing power outages	☐	☐	☐	☐	☐
Minimizing the visual impacts of electrical infrastructure and equipment	☐	☐	☐	☐	☐
Helping customers understand how to manage their energy consumption	☐	☐	☐	☐	☐

2. FortisBC is predicting that small gaps will exist in energy supply during the winter months for the next 5 years. At the current time it is believed that contractual agreements with BC-based suppliers are the best option for meeting these needs rather than building additional physical generation at this time. Please indicate whether you strongly agree, somewhat agree, neither agree or disagree, somewhat disagree, or strongly disagree with this resourcing option. *Check one box only*

Strongly agree ☐
Somewhat agree ☐
Neither agree or disagree ☐
Somewhat disagree ☐
Strongly disagree ☐

3. As you heard this evening, FortisBC believes that a reserve margin of firm generation resources is required to reliably supply power to its customers. This insurance, known as the Planning Reserve margin, would be in place to protect against extremes in weather, the unplanned loss of other generation or transmission, and/or unanticipated growth in demand.

Please indicate whether you think the Planning Reserve margin should definitely be considered, probably be considered, probably not be considered, or definitely not be considered. *Check one box only*

Should definitely be considered ☐
Should probably be considered ☐
Should probably not be considered ☐
Should definitely not be considered ☐

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Questionnaire – Part 2

4. Would you definitely, likely, likely not, or definitely not pay a higher price for electricity to support the insurance that a Planning Reserve Margin would provide? *Check one box only*

Definitely ☐ Likely ☐ Likely not ☐ Definitely not ☐

5. When determining future project and equipment expenditures, FortisBC considers factors such as safety, reliability and cost. You the customer and your community may consider other factors to also be important. Please identify how important the following factors are to you when considering future expenditures.

	Very important	Important but not critical	Not very important	Not at all important
Distance from other buildings and amenities (homes, schools, parks, etc.)	☐	☐	☐	☐
Environmental values (impact on natural habitat, impact on wildlife, "no net loss" of habitat)	☐	☐	☐	☐
Visual appearance of electrical equipment	☐	☐	☐	☐
Effects on community/neighbourhood during construction	☐	☐	☐	☐
Timeliness of construction versus need for project	☐	☐	☐	☐
Flexibility for future growth	☐	☐	☐	☐
Impact on customer rates	☐	☐	☐	☐

6. Customers are telling FortisBC that they want to see additional social and environmental components added when capital projects are undertaken. This could include additional visual screening (vegetation, berming or fencing), special environmental treatment, or other community specific amenities.

Please indicate whether you think visual screening, special environmental treatments or other community specific amenities should definitely be considered, probably be considered, probably not be considered or definitely not be considered for inclusion in capital project planning. *Check one box only*

Should definitely be considered ☐ Should probably not be considered ☐
Should probably be considered ☐ Should definitely not be considered ☐

7. If FortisBC were to include social and environmental considerations within capital project budgets, what percentage do you feel would be reasonable to add to each project budget (i.e. 1% = $1,000 for every $100,000 of project budget)? *Check one box only*

None ☐ 1% ☐ 2% ☐ 3% ☐ More than 3% ☐

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Questionnaire – Part 2

8. Would you definitely, likely, likely not, or definitely not pay a higher price for the electricity you buy at home in order to include social and environmental components (i.e. additional visual screening, special environmental treatments or other community specific amenities) in capital project budgets? *Check one box only*

Definitely ☐ Likely ☐ Likely not ☐ Definitely not ☐

9. In the recent presentation and booth session you learned that FortisBC is proposing a switch from time-based infrastructure management to condition-based infrastructure management. This change in management systems will require an initial investment but should result in more cost-effective use of maintenance dollars. Please indicate whether you think the change to condition-based infrastructure management should definitely be considered, probably be considered, probably not be considered or definitely not be considered by FortisBC. *Check one box only*

Should definitely be considered ☐ Should probably not be considered ☐
Should probably be considered ☐ Should definitely not be considered ☐

10. Please explain the reason for your answer: ____________________

11. Tonight you heard FortisBC discuss the new Automated Metering Infrastructure (AMI) or smart meters that will be implemented as part of the Integrated System Plan once approved by the B.C. Utilities Commission. As part of this program FortisBC would provide free access to a secure website for customers to review energy usage information.

There would also be the option for customers to have in-house meters for reviewing energy usage data without having to access the Internet. FortisBC would like your feedback on whether in-home displays should be installed for all customers as a component of the AMI project OR if this technology should be optional. Please select which option you prefer: *Check one box only*

Basic in-home displays should be provided for all customers as part of the AMI project ☐
In-house meters should be optional and purchased by the customers at local retailers ☐

12. Why is this your preferred option? ____________________

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Questionnaire – Part 2

13. If the decision is made for in-house meters to be optional, FortisBC may provide financial incentives to customers who purchase them. Please indicate whether you strongly agree, somewhat agree, neither agree or disagree, somewhat disagree, or strongly disagree that FortisBC should offer an incentive program. *Check one box only*

Strongly agree ☐ Somewhat agree ☐ Neither agree or disagree ☐ Somewhat disagree ☐ Strongly disagree ☐

14. If the purchase of in-home displays is implemented on an optional basis, consumers would have the choice from a variety of meters which range in price from approximately 25 to 150 dollars. As the cost of the meter goes up the energy usage information becomes more detailed. If you were to purchase the in-home meter from a store, what price would you be willing to spend? *Check one box only*

Less than 25 dollars ☐ 25 to 49 dollars ☐ 50 to 100 dollars ☐ More than 100 dollars ☐

15. As previously mentioned FortisBC plans to provide a secure website to view your energy usage information, would you definitely use, likely use, likely not use, or definitely not use the website to track your energy usage? *Check one box only*

Definitely use ☐ Likely use ☐ Likely not use ☐ Definitely not use ☐

16. Please explain the reason for your answer:____

17. Based on what you have heard about advanced metering or smart meter projects in other places, what comments, if any, would you like to make about this type of project?

18. Before advanced meeting is installed in your community, what additional information would you like about the program?

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Questionnaire – Part 2

19. As part of the Demand Side Management Plan, FortisBC and Terasen Gas are exploring the idea of offering joint programs to encourage energy efficiency among residents in the region. Please indicate whether you strongly agree, somewhat agree, neither agree or disagree, somewhat disagree, or strongly disagree that this would be a beneficial partnership. *Check one box only*

Strongly agree ☐ Somewhat agree ☐ Neither agree or disagree ☐ Somewhat disagree ☐ Strongly disagree ☐

20. What energy efficiency and conservation programs, if any, would you like FortisBC to introduce in the future?

21. Was there anything in the presentation that was confusing or difficult for you to understand? Yes ☐ No ☐

22. If you answered **YES** to the previous question, what was confusing or difficult to understand about the presentation?

23. Thinking about everything you have heard tonight, please indicate whether you strongly agree, somewhat agree, neither agree or disagree, somewhat disagree, or strongly disagree that the Integrated System Plan fulfills FortisBC's objective of planning for the electrical needs of then next 20 to 30 years.

Strongly agree ☐ Somewhat agree ☐ Neither agree or disagree ☐ Somewhat disagree ☐ Strongly disagree ☐

24. It is important to FortisBC that customers are informed about the Integrated System Plan. The presentation tonight was one way of communicating with customers and getting their feedback. Considering the information you were given, please indicate whether you strongly agree, somewhat agree, somewhat disagree, or strongly disagree that the presentation material:

	Strongly Agree	Somewhat Agree	Somewhat Disagree	Strongly Disagree
Helped me understand the Integrated System Plan better	☐	☐	☐	☐
Was a balanced perspective on the Integrated System Plan	☐	☐	☐	☐

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Questionnaire – Part 2

25. Are there any other thoughts or comments you would like to make?

When you are done, please put your pencil down and wait for the facilitator to provide further instructions.

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