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**BRITISH COLUMBIA
UTILITIES COMMISSION**

**ORDER
NUMBER** C-11-07

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**IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473**

and

**An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
Distribution Substation Automation Program**

BEFORE: L.A. O'Hara, Panel Chair
and Commissioner
P.E. Vivian, Commissioner December 24, 2007

O R D E R

WHEREAS:

- A. The Application was requested by the Commission in the Reasons for Decision accompanying Order No. G-52-05, dated May 31, 2005, which was issued following the Commission's consideration of FortisBC Inc.'s 2005 System Development Plan; and
- B. On August 28, 2007 FortisBC Inc. ("FortisBC") submitted an application to the British Columbia Utilities Commission ("Commission"), pursuant to Sections 45 and 46 of the Utilities Commission Act, for a Certificate of Public Convenience and Necessity ("CPCN") for the Distribution Substation Automation Program ("the Program"); and
- C. FortisBC states that the Program is estimated to cost \$6.38 million and is required to enable improved substation data collection, remote equipment operation, improved distribution reliability, and enhanced power system planning and safety; and
- D. The Program consists of installing automated control and data acquisition systems in 28 existing substations. All equipment design and operation is consistent with the equipment currently being installed in new substations in the FortisBC service territory; and

- E. The Program is scheduled to commence in 2007 and to be completed by the end of 2011; and
- F. On September 18, 2007, by Order No. G-108-07, the Commission directed that a Written Public Hearing be utilized for deciding the matters brought forward in the Application, established a Regulatory Timetable for the proceeding and directed FortisBC to provide notification to all Intervenors and Interested Parties who had participated in two previous proceedings, namely FortisBC – 2008 Revenue Requirements, 2007-2008 Capital Expenditure Plan and 2007 Update; and FortisBC – 2006 FortisBC Inc., and Princeton Light and Power Company Limited (“PLP”), Application to Transfer Shares and Assets of PLP to FortisBC and to Wind Up PLP; and also to notify British Columbia Hydro and Power Authority and British Columbia Transmission Corporation; and
- G. On November 14, 2007, the Commission extended the regulatory agenda at the request of FortisBC and with the agreement of the other Intervenors; and
- H. The British Columbia Old Age Pensioners’ Organization *et al.*, BC Coalition of People with Disabilities, Council of Senior Citizens’ Organizations, federated anti-poverty groups of BC, and Tenant Resource and Advisory Centre (collectively known as BCOAPO *et al.*) filed its written submission on the Program (December 11, 2007); and
- I. Mr. Alan Wait filed a written submission on the Program (December 11, 2007); and
- J. Mrs. Beryl (Slack) Goodman filed a written submission on the Program (November 13, 2007); and
- K. The FortisBC Reply Submission dated November 30, 2007 completed the written review process; and
- L. The Commission has considered the Application and has determined that the Program is in the public interest and that a CPCN be granted to FortisBC for the Reasons for Decision attached to this Order.

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NOW THEREFORE pursuant to Sections 45 and 46 of the Utilities Commission Act, the Commission orders as follows:

1. A CPCN is granted to FortisBC for the Distribution Substation Automation Program as set out in the Application.
2. FortisBC will file with the Commission, Semi-Annual Progress Reports on the Program. The progress report format will be generally as set out in Appendix B to this Order.
3. The Semi-Annual Progress Reports will be filed within 30 days of the end of each reporting period.
4. FortisBC is directed to file with the Commission a Final Report and Post-Implementation Report, as outlined in Appendix B, within six months of the end or substantial completion of the Program that provides a complete breakdown of the final costs of the Program, compares the final costs to those included in the Application, and provides an explanation and justification of variances.
5. FortisBC, as part of its Annual Review and Revenue Requirements, is to file with the Commission the elements of the Program Effectiveness Report as outlined in Appendix B.
6. FortisBC will comply with all directions as set forth in the attached Reasons for Decision in Appendix A.

DATED at the City of Vancouver, in the Province of British Columbia, this 24th day of December 2007.

BY ORDER

Original signed by

L.A. O'Hara,
Panel Chair and Commissioner

Attachments

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
Distribution Substation Automation Program

REASONS FOR DECISION

1.0 INTRODUCTION

1.1 Background

The Application was requested by the Commission in the Reasons for Decision accompanying Order No. G-52-05, dated May 31, 2005, which was issued following the Commission's consideration of FortisBC Inc.'s ("FortisBC") 2005 System Development Plan. That Decision stated (in part):

"Distribution Substation Automation: This [CPCN] is required because it is not clear to the Commission Panel what the possible risks and benefits are associated with the Program, what precedent it may set for future Programs, and if FortisBC is selecting the appropriate technology" (Reasons for Decision, p. 62).

1.2 The Application

On August 28, 2007, FortisBC applied for a Certificate of Public Convenience and Necessity ("CPCN") to the Commission pursuant to Sections 45 and 46 of the Utilities Commission Act, (the "Application") for the Distribution Substation Automation Program (the "Program") at an estimated cost of approximately \$6.38 million.

The Program includes the installation of automated systems in distribution substations to gather and analyze data so that decisions can be made more quickly and effectively. It is a multi-year staged program that focuses on reducing operational costs, preventing power outages and restoring power more quickly when there is a failure, as well as improving the levels of safety to employees and the public.

This Application proposed implementing solutions for monitoring and control of the system as opposed to the more complex load restoration and auto-transfer schemes. A standard package of protection, monitoring and data collection equipment and system has been developed by FortisBC and is being applied to all new substation construction. The scope of this Application involved the installation of these systems to 28 substations that are not currently slated for major upgrade or replacement in the foreseeable future.

Longer term benefits include more targeted maintenance planning. A list of the benefits associated with this Program is described in detail in this Application. As described herein, savings are forecast to be realized in future operating and capital budgets as well as the potential deferral of some capital expenditures.

The Program was proposed to commence in 2007 at a capital cost of \$6.38 million to be completed by the end of 2011. The Program net present value ("NPV") was originally estimated at \$1.30 million with a one-time equivalent rate impact of 0.05 percent and later was revised by the FortisBC response to British Columbia Utilities Commission ("BCUC", the "Commission") Information Request ("IR") No. 2 (Exhibit B-1, p. 2).

1.3 The Public and Regulatory Process

As the Program did not require large new infrastructure to be constructed (the majority of the work will be carried out within the substation control buildings), no public consultation was undertaken prior to the Application being submitted (Exhibit B-1, p. 37).

By Order No. G-108-07, the Commission directed that a Written Public Hearing be utilized for deciding the matters brought forward in the Application, established a regulatory timetable for the proceeding and directed FortisBC to provide notification to all Intervenors and Interested Parties who had participated in two previous proceedings, namely FortisBC-2008 Revenue Requirements, 2007-2008 Capital Expenditure plan and 2007 Update; and FortisBC-2006 FortisBC Inc., and the Princeton Light and Power Company Limited Application to Transfer Shares and Assets of PLP to FortisBC and to Wind Up PLP. Additionally, FortisBC was to notify British Columbia Hydro and Power Authority and British Columbia Transmission Corporation. The regulatory agenda was later extended at the request of FortisBC and the agreement of the Intervenors by the Commission's letter of November 14, 2007.

Registered Intervenors for the proceeding were the BC Old Age Pensioners' Organization *et al.* ("BCOAPO"), Mr. Alan Wait, the Ministry of Energy, Mines and Petroleum Resources, and Mrs. Beryl (Slack) Goodman, Interested Party.

2.0 THE DISTRIBUTION SUBSTATION AUTOMATION PROGRAM

2.1 Present Design Practices and Equipment Standards

The items listed below, complete with their purpose, comprise the major automation systems that FortisBC is currently applying to new construction and is intending to apply to the legacy substations identified in this Application. It is important to note that:

- a. The technology cited is not "cutting edge" or beta version. It is highly functional and has been market available long enough to have been reviewed and tested by many utilities; and
- b. FortisBC has installed this technology in other substations as part of recent upgrades. The equipment has been successful in enabling the desired outcomes. No untried technology is proposed as part of this Program.

2.1.1 Protection Relays

FortisBC has standardized on a single manufacturer for standard protection relays, Schweitzer Engineering Laboratories, Pullman WA, USA, for protection relaying equipment, which reduces costs by reducing the number and variety of spare devices that must be maintained in inventory. Similarly, this common platform reduces training costs as there are fewer devices for technicians and engineers to become familiar with and ensures that the technicians have a good and ongoing understanding of the equipment as it is worked with routinely (Exhibit B-1, p. 7).

2.1.2 Power-Quality Monitoring

These electronic meters will replace antiquated electromechanical metering and are increasingly important in assisting FortisBC in planning system expansion due to load growth by reporting the power that is being delivered to any given location. These meters allow FortisBC to track and the resolve power quality problems much more quickly than would otherwise be possible using antiquated electromechanical meters.

The meters, from Schneider Electric (Power Measurement Ltd.), Victoria B.C., are linked to an existing central monitoring and logging system, which captures and stores the information for later use in a number of applications, such as power system load modeling. The database server is designed for high availability and has multiple central processing units (“CPUs”), hard drives and power supplies. The database contents are backed up nightly onto tape drives; these tape archives are then stored offsite for disaster survival (Exhibit B-1, p. 8).

2.1.3 Digital Fault Recorders (“DFRs”)

DFRs are only installed at major terminal stations and are used to provide a complete record of station conditions when a fault or electrical disturbance occurs. In general, these devices are not installed in distribution substations; however, a sufficient subset of their functionality is available in the protection and metering equipment discussed in the previous sections and is considered adequate for distribution-class substations (Exhibit B-1, p. 8).

2.1.4 Communications

The inter-substation communications infrastructure, dictated by station age and criticality within the power system that is in-use or accepted by FortisBC included the following:

- Fibre-optic multiplexing equipment is used at larger substations and generating plants and provides very high bandwidth between these locations.
- Licensed 950 MHz digital wireless communications are used for critical data such as System Control and Data Acquisition (“SCADA”) communications since unlicensed systems are not considered secure or reliable enough for multi-point SCADA data links.
- Satellite low-bandwidth communications are used at a number of remote substation locations to link them to the FortisBC System Control Center and are used to provide communications to isolated areas where other facilities are either not available or would be cost prohibitive to install.
- Unlicensed 900 MHz digital wireless communications are used to provide non-critical corporate wide-area network access to substation meters and relays and used in limited cases for point-to-point SCADA communications.
- POTS (plain old telephone service) dial-up lines are used at numerous locations to provide remote access to relays and meters.
- Cellular data and telephone leased lines are used in locations where SCADA communication is required, but no alternate communication infrastructure is available, and provide a permanent connection to the remote location (Exhibit B-1, pp. 9-10).

2.2 Scope of Work

2.2.1 Stations Included in the Program Scope

The 28 stations that will remain as part of the power system and are not currently slated for major upgrade in the next few years form the scope of the Program, and are identified in Table 1 (Exhibit B-1, 3.1.5 Stations Included in the Program Scope, p. 11).

2.2.2 Stations Excluded

The other legacy substations are not included in the Program as they will be retired in the near future or their status is under review (Exhibit B-1, 3.2, Stations Excluded, pp. 12-13).

2.2.3 Individual Scopes of Work

Table 2 (Exhibit B-1, 3.3, Individual Scopes of Work, pp. 14-16) describes the high-level scope of work required for the individual substations identified in Table 1 (Exhibit B-1, 3.1.5, Stations Included in the Program Scope, p. 11).

2.3 Program Schedule

Past Regulatory approval, FortisBC plans to complete detailed scoping and estimating (+/-10 percent) material takeoffs and vendor negotiations, and initial engineering design and procurement. Any material changes to the estimated costs will be reported to the Commission (Exhibit B-2, BCUC 1.9.2, p. 16). Program on-site construction will commence in 2008 with completion in 2011.

The relative priority ranking scale described in Table 1 also represents the year of implementation. The construction schedule is summarized in Table 3 (Exhibit B-1, 3.4 Program Schedule, p. 17).

2.4 Program Cost

As described in Table 4 (Exhibit B-1, 3.5 Program Cost, p. 21), the total cost of the Program is estimated to be \$6.38 million (+/-25 percent) with expenditures occurring over a five-year period. This figure is in as-spent dollars and includes a 10 percent contingency allowance. Any material changes to the estimated costs will be reported to the Commission (Exhibit B-2, BCUC 1.9.2, p. 16). This estimate compares favourably with the \$5.8 million cost that was originally submitted in the FortisBC 2005 System Development Plan (as that value was in 2004 dollars). The apparent increase is due to inflation since that time and over the installation period of the Program.

The Program NPV was estimated at \$1.301 million with a one-time equivalent rate impact of 0.05 percent and later was revised by FortisBC's response to BCUC IR No. 2. A detailed calculation of the revenue requirements was presented in Appendix 1 (Exhibit B-1, Appendix 1 – Revenue Requirements Analysis, p. 39). For the purposes of this application the revenue requirements calculation was carried out for a lifespan of 20 years as much of the equipment to be installed by the program is expected to reach this lifespan.

In calculating the Program NPV an “Annual Cost Reduction” was applied as a reduction to future operating and capital costs (Exhibit B-1, Table 5 - Program Benefits, p. 23). This value is the estimated yearly savings that are expected to be achieved upon completion of the Program. An average of the “Estimated Minimum” and “Estimated Maximum” values was used in the calculation as an assumption. Thus, a value of \$590,000 has been used for the initial savings starting in 2011. This cost reduction has been apportioned as follows: 20 percent of the savings (\$118,000) to a reduction in operating costs (line 56 in Appendix 1) and 80 percent of the savings (\$472,000) to a reduction in future capital costs (line 48 in Appendix 1). This allocation was chosen as the majority of the quantifiable program benefits, due to remote operation of switching devices will be attributed to future capital Programs. This is true even for forced outages. For widespread outages the benefits of automation would be most applicable in that the outage costs would be capitalized due to the large amount of power system infrastructure that is replaced. Note that the financial benefits listed in Table 5 are partially offset by additional operating costs (mainly due to leased-line and communications monthly charges) that will be required for some installations.

In the Application, the depreciation and replacement costs were adjusted to take into account that the majority of the equipment would have a 20-year lifespan, some of the assets would have a five-year lifespan, other assets would have a ten-year expected lifespan and replacement assets that previously did not appear in the NPV calculations.

Hence, in BCUC IR No. 2, FortisBC was requested to modify and resubmit Appendix A26.1 from BCUC IR No.1 to include the replacement of server hardware every five years and the replacement assets from Appendix A26.5 BCUC IR No. 1. FortisBC submitted the revised Appendix A44.1 in response to this request (Exhibit B-5, BCUC IR No. 2, 2.44.1, p. 26).

The modifications resulted in the elimination of negative depreciation, negative additions to plant, a revised Program NPV of Revenue Requirements estimated at \$4.516 million and a resulting increase to the one-time equivalent rate impact from 0.05 percent to 0.18 percent (Exhibit B-5, BCUC IR No. 2, 2.44.1(b), lines 1-9).

2.5 Program Justification

FortisBC states that the ultimate goal of implementing the Substation Automation Program is to improve employee and public safety, power quality and reliability as seen by the customers. In this Section, specific examples are provided to demonstrate the actual improvements and resulting benefits. These benefits are both immediate and long term and are summarized in Table 5 and described in detail in this Section (Exhibit B-1, 4, Program Justification, p. 23).

2.5.1 Remote Visibility

Provides the complete load profile information (both real and reactive power) for each distribution feeder capacity at a supply point and accurate real-time system loading information on the station ambient temperature and the power transformer oil and winding temperatures.

Reduces the duration and frequency of outages, the troubleshooting time by skilled workers, and exposure of the customer to both increased cost and longer and/or avoidable outages (Exhibit B-1, p. 24).

2.5.2 Load Forecasting

Detailed and accurate load information is required to make correct network planning decisions. With historical station load and load factor data information available, it is possible to deploy capital expenditures in a strategic fashion. Modern meters have the capability to record data on a periodic interval. From this data an accurate load profile and load factor can be calculated (Exhibit B-1, p. 25).

2.5.3 Maintenance Planning

An automated critical information data-collection platform assists FortisBC in making effective maintenance decisions that direct the maintenance schedule including reducing the annual inspection cost (Exhibit B-1, pp. 25-26).

2.5.4 Revenue Protection and Loss Analysis

FortisBC's total system losses are estimated to be 9.5 percent, while system modelling has calculated technical losses to be in the area of 9 percent. Using the average annual load, the total system average losses are in the order of 38 MW. The Program could produce significant potential for cost savings by reducing both un-metered and technical losses through more accurate information (Exhibit B-1, pp. 26-38).

2.5.5 Safety

The Program enables the System Control Center to gain visibility of critical alarms in real-time thus emergency response procedures can also be activated more quickly, reducing public and environmental risks since emergency response procedures can also be activated more quickly (Exhibit B-1, pp. 28-29).

2.5.6 Operating Authority

With the Program, System Control Center Person in Control ("PIC") duties received notable benefits such as the degree of employee safety which was considered to be higher since control and status of the system was under the control of a single entity, and the field crews were engaged in power restoration and operation and less so in performing PIC duties while in the field. Also, annual operation costs could be reduced by as much as \$100,000 depending on the number of outages and the number of crews working on the power system (Exhibit B-1, pp. 29-30).

2.5.7 Remote Operation

The Program provides several distinct and discrete benefits associated with having a greater degree of SCADA visibility and control at the System Control Center.

- a. Reliability that reduces outage duration and the time restoration crews must travel,
- b. Energy metering that improves system performance and reduces energy costs, and
- c. Automatic Recloser operation enabling and disabling reclosers using remote control avoids these labour costs in a safe manner.

(Exhibit B-1, pp. 30-33)

2.5.8 Metering

The Program will greatly enhanced the ability to acquire specific time based load data on individual feeder metering, provide more accurate load profiling, assist in system load balancing, reduce the potential for outage and minimize the strain placed on power system equipment, and guide in the deployment of capital expenditures (Exhibit B-1, p. 33).

2.5.9 “Intelligent” Relaying

The Program provides electronic “intelligence” so that troubleshooting and restoration can be directed to the problem, with much less time spent by technicians trying to identify and locate the problem. Specific data that will be acquired and logged includes Fault Location, Fault Recording, Condition Monitoring, and Transformer Replacement (Exhibit B-1, pp. 33-35).

2.5.10 Reduced Maintenance Costs

The Program will upgrade all remaining electromechanical meters and relays on distribution feeders. This will reduce future maintenance costs as routine relay testing will no longer be required and the difficulty of obtaining replacement parts will not continue to be an issue. Some forced relay upgrades have already occurred when devices have failed and it was either impossible to locate spare parts or it was not cost effective (Exhibit B-1, p. 36).

2.5.11 System Integrity and Security

The Program provides that standards be met and the inherent system security be employed. The FortisBC standard is to ensure forced separation of the operational power system controls such as relaying and SCADA, and those functions that are “read only”, including data logging and equipment monitoring. Unauthorized access and operation is also prevented, enhancing power system “cyber-security” (Exhibit B-1, pp. 36-37).

2.5.12 Central database

The Program will install new server hardware and software in the FortisBC Data Centre. This server will be responsible for collecting, aggregating and archiving the data that is received from numerous data sources. These sources include the SCADA system, the power-quality metering system and the Computerized Maintenance Management System. The server will provide a user-friendly web-based interface that will allow users to easily retrieve both historical and real-time data. This data provides a more reliable predictor of future performance, allows planning engineers to evaluate system needs based on actual performance, and provides customers greater levels of reliability and lower future costs (Exhibit B-1, p. 37).

2.6 Other Applications and Approvals

FortisBC stated that no approvals from agencies other than the Commission were required (Exhibit B-1, p. 38).

3.0 EXAMINATION OF ISSUES and ARGUMENTS

3.1 Commission Issues

The Commission queried FortisBC on the Computerized Maintenance Management System, (“CMMS”), technology, cyber-security standards, safety, cost savings, benchmarks, performance based targets, timing, automation of manually operated devices for remote operation, and the costing used in Appendix A26.1 to include server hardware replacements and replacement assets from Appendix 26.5 (Exhibit A-2, Commission IR No. 1 to FortisBC; Exhibit A-3, Commission IR No. 2 to FortisBC).

3.2 FortisBC’s Argument

In its Argument, FortisBC submits that the Program is justified because it will provide direct benefits to FortisBC’s system and the informational starting point from which to obtain future benefits, particularly when paired with Advanced Metering Infrastructure (“AMI”), and because it is in line with the 2007 Energy Plan. FortisBC submits that these benefits will be achieved at a conservative rate impact of .05 percent with the likely results being a zero or positive impact on rates. In FortisBC’s submission, only a conservative estimate of a 0.1 percent reduction in line losses or \$ 0.24 million per annum incremental savings will bring the Program NPV to zero (FortisBC Argument, pp. 3, 5).

FortisBC summarizes the Program benefits as follows:

- (a) a reduction in operating and capital costs estimated at \$ 0.59 million;
- (b) a reduction in the duration of customer outages;
- (c) an improvement in safety;
- (d) an ability to provide a detailed load and reactive power profile for all substations and feeders;
- (e) an ability for a focused reduction of system losses, including an improvement in the informational capability to identify and reduce system losses together with AMI;
- (f) supportive of the 2007 Energy Plan and enhancement of FortisBC’s electrical system by way of providing the underpinnings for the “smart electricity grid” concept; and
- (g) greenhouse gas reductions related to reduced crew travel for manual switching and recloser tagging (FortisBC Argument, pp. 3-4).

3.3 Intervenor Issues

Only two intervenors submitted IRs during the written process; these were Mr. Wait and BCOAPO.

1. Mr. Wait’s issues appear to be related to system losses and the calculations in Appendix A (Exhibit C2-2, Information Request from Alan Wait).
2. BCOAPO’s issues were related to system losses, potential savings, suitability of the technology to be employed, and the program benefits to be realized (Exhibit C3-2, BCOAPO IR No. 1).
3. Mrs. Goodman did not submit any information requests and her final submission recommended approval of the Program.
4. Electricity Policy Branch of MEMPR did not submit any information requests or a final submission.

3.4 Mr. Alan Wait's Remaining Issue

Mr. Wait has expressed a concern regarding the Return on Equity ("ROE") Sharing Mechanism and whether or not the mechanism is fair to both FortisBC and the ratepayers.

"However, this application has raised many questions with me about how the present Return on Equity (ROE) Sharing Mechanism works, and whether the mechanism is fair to both FortisBC and the ratepayers. I would urge the British Columbia Utilities Commission to have the ROE Sharing Mechanism reviewed publicly at the earliest opportunity. The present Sharing Mechanism requires FortisBC to increase operating and maintenance efficiency each year. This is done through capital expenditures such as this CPCN Program, for which the ratepayers will have to cover all the capital costs in the rates, but reduced operating costs beyond the required annual efficiency improvement are shared with FortisBC. I have not had much to say on the sharing mechanism in the past, as I had not taken the time to thoroughly understand the implications of the mechanism. This CPCN has really peaked my concerns as to whether the ROE sharing mechanism is properly structured."

3.5 BCOAPO's Remaining Issue

BCOAPO's issue involves the FortisBC opportunity to reduce system losses. BCOAPO alleges the Program by itself, cannot provide the information to accurately assess system losses at the distribution feeder level and will require AMI. BCOAPO feels a response from FortisBC on this matter would be useful.

"Part of our support for this Program is predicated on an opportunity to reduce system losses, as even small reductions will result in significant savings to customers. In response to BCUC IR 34.2, FortisBC outlines plans to file an Automated Metering Infrastructure ("AMI") CPCN application in the near future, in order to install real-time AMI metering at the end customer level. The Company also states in response to the same IR that neither the Program nor AMI by itself can provide the information to accurately assess system losses at the distribution feeder level. It is our understanding that reductions in system losses as a result of this Program do not require AMI at the end customer point. It would be useful for FortisBC to comment in its Reply Submission on whether savings in system losses are dependent on full-scale automated metering at the customer level."

3.6 FortisBC's Reply Argument

FortisBC replied to the issues raised by Mr. Wait and BCOAPO and noted that neither opposed the Application.

In regards to Mr. Wait's issues, FortisBC submitted that increasing the Company's efficiency beyond an annual productivity improvement factor is a desired outcome of performance based regulation. FortisBC further submitted that most of its operating savings are achieved through cost control and productivity improvement efforts in its operations and that only a very small portion of cost savings result from capital expenditures. FortisBC intends to reflect the cost savings associated with this Program in its Revenue Requirements and will address this aspect as part of its 2009 Revenue Requirements Application.

BCOAPO questioned whether the benefits used in the Program analysis may include benefits attributable to equipment installed at substations not included in the Program. FortisBC confirmed that the analysis of benefits was based on only the substations that are included in the Program.

In reply to BCOAPO's query with reference to full-scale automated metering at the customer level, FortisBC states that identification of transmission system and substation losses would not require the installation of AMI. At the distribution feeder level, neither feeder loss reduction through better overall allocation of loads between individual substation feeders, nor feeder-level power factor correction (by installation of capacitors) would require AMI. However, targeted loss reductions at the feeder level, which could be addressed by knowing the instantaneous real losses on a per-feeder basis would require AMI.

BCOAPO requested that FortisBC report on the +/- 10 percent cost estimate during the 2008 Annual Review and FortisBC confirmed that it will do so.

Commission Determination

The Commission Panel directs FortisBC to address the cost savings associated with this Program as part of its 2009 Revenue Requirements Application and on an annual basis thereafter until one year following the completion of the Program. Further, FortisBC is directed to report on the +/- 10 percent cost estimate as part of the first semi-annual report as set out in the Order.

4.0 TECHNOLOGY OVERVIEW FOR SUBSTATION AUTOMATION

The Application's Executive Summary sets out the range of matters that can fall under the general rubric "Automation" (Application, p. 2).

"The term "automation" can imply a range of complexity. Systems can consist of relatively simple data logging and monitoring, or they can extend to highly automated schemes that can provide automatic restoration of customer load following system outages. This Application proposes implementing solutions for monitoring and control of the system as opposed to the more complex load restoration and auto-transfer schemes. A standard package of protection, monitoring and data collection equipment and system has been developed by FortisBC and is being applied to all new substation construction. The scope of this Application involves the installation of these systems to substations that are not currently slated for major upgrade or replacement in the foreseeable future.

This Program broadens the integration and use of remote monitoring and control to distribution level substations, including the quality monitoring of lines, transformers and feeders, fault recording and locating, and equipment condition monitoring. It will provide common communication mechanisms for gathering, storing, accessing and analyzing the accumulated data. The Program includes the development of a central data repository, individual equipment installation Programs in appropriate substations, and an emergency backup plan" (emphasis added).

In some of the device and applications areas, the technology is changing so quickly that the timing of any Program will influence the system architecture, communications protocols and vendor selection. Today's state-of-the-art quickly becomes tomorrow's obsolescence.

In response to BCUC IRs 15.1 and 16.2, FortisBC supplied three relevant papers dealing with the status of automation Programs throughout the electricity world (The Sierra Energy Group T & D Automation Market Summary, June 2006; a Quebec Hydro Case Study dealing with pole-top devices; and an IEEE Power Engineering Society Research Plan for Advanced Distribution Automation). The Commission Panel found these most helpful in evaluating the "state-of-the-art" for automation of electric utility transmission and distribution.

The Sierra Energy study involved a survey of 664 utilities in Canada and the United States and gathered information on current systems and suppliers, and communications types and protocols. The number of separate Programs identified was 490. Significantly for utility planning in this province, the study found that “many utilities have simultaneously begun moving ahead with communication upgrades with the intention of using their increased bandwidth to accommodate both new SCADA and distribution automation systems along with automated meter reading.” For the U.S. utilities, the sense was that the numerous programs were being stimulated by pressure from the North American Electric Reliability Corporation of the United States of America (“NERC”) and the Federal Energy Regulatory Commission of the United States of America (“FERC”) to improve network reliability and strengthen utility network interconnects following upon the August 14, 2003 “Black-Out” that put 50 million people in the dark. The study noted that substation automation was the second highest category of program activity by dollar amount and the highest category for number of programs.

FortisBC has already substantially completed the automation of the Company’s transmission stations and thus the proposed Program is not being driven by interconnection reliability issues. Since FortisBC already follows the intent of the NERC Critical Infrastructure Protection (“CIP”) standards it is not felt that there is any additional benefit that would be gained by waiting for the formal adoption of the standards (Exhibit B-5, BCUC 2.39.2, p. 23).

There is nothing in the studies and material that has been reviewed by the Commission Panel that is inconsistent with the general approach to substation automation being proposed by FortisBC. However, the secret to program success seems to be a balancing of program costs with the desired functionality and benefits and always with a view to easy future upgrades and the trends away from proprietary software and communications protocols and towards open systems design.

A detailed analysis of systems standardization within the Province of British Columbia, Canada and the United States goes beyond the scope of this proceeding and yet is pivotal to the selection of the appropriate systems architecture and communications protocols. However, the Commission Panel has received some comfort on this front where FortisBC, in response to BCOAPO’s IR 1.2.1 responds as follows:

“The protection, metering, communications and RTU hardware proposed by the Program is used by the majority of electric utilities in North America. As a local example, BC Hydro/BCTC installs essentially the same protection, metering and RTU hardware as FortisBC.”

Also, in response to BCUC 1.7.5, FortisBC reported that it was working with other utilities in B.C. to determine how (or if) the NERC Reliability Standards (including the CIP Cyber Security Standards), might be implemented within the BC regulatory framework.

Commission Determination

The Commission Panel therefore concludes that replacing the existing legacy technology with new electronic technology is appropriate.

5.0 SCOPE OF THE PROGRAM AND TECHNOLOGY SELECTION BY FORTISBC

The Program is restricted to system components that will provide for improved monitoring and control only. The scope of the program at this stage, does not include load restoration and auto transfer (BCUC 17.1) although the FortisBC 2006 System Development Plan Update does include a reference to “automated load restoration” as part of the overall program. The technology cited by FortisBC is not “cutting edge” or beta version (Application, p. 7).

The various components of the Program are outlined in Section 2.0 above.

In general, FortisBC will purchase from a single supplier and states that the suppliers selected “have established records of supporting legacy devices for a reasonable duration after their introduction” (Exhibit B-2, BCUC 1.20.1). Possible early equipment obsolescence is present in any system upgrade, particularly those involving computerized systems and communications protocols but legacy support assurance neutralizes this concern in part. If the Program is approved, FortisBC will seek a Request for Quotation from the selected suppliers based on the total equipment requirement for the Program (Exhibit B-2, BCUC 1.21.1).

As currently proposed, the Program will provide future functionality to connect to the Company’s CMMS.

Commission Determination

The Commission Panel therefore concludes that replacing the existing technology with new electronic technology that is compatible with current FortisBC proven electronic technology, even though it limits the suppliers, is appropriate. The Commission Panel also concludes that this new electronic technology should meet certain future functional CMMS capability requirements and future remote operation of devices and security requirements.

6.0 RISKS AND BENEFITS

The anticipated Program benefits are set out in Section 4 of the Application and in summary form in Table 5 – Program Benefits. Where possible, an estimate of the range of annual cost savings is made and on a total Program basis, the estimated annual cost savings is in the range of \$482 K to \$697 K. Other benefits are listed but do not lend themselves to a cost reduction estimate. The largest component of the estimated savings comes from the anticipated reduction in customer outage hours per year, which are estimated to save \$397 K annually.

The enumerated estimated dollar benefits in Table 5 are small compared with what might be realized in terms of savings in line loss reduction. In the Application (p. 28), the savings in this one area alone are calculated as up to \$2.4 million annually. FortisBC in its response to BCUC IR No. 2, stated that FortisBC has estimated that each 1.0 percent (absolute) loss reduction represents potentially \$2.4 million in annual savings to customers for which no credit was applied to the NPV analysis of the current Application. If the Program was able to identify projects that result in a loss savings of only 0.1 percent per year, then the additional savings (approximately \$240,000) would result in the Program NPV going to zero. If loss reductions beyond 0.1 percent are identified by the Program then they would have a further positive financial benefit for the customer. Since a reduction of losses by 0.1 percent is conservative, FortisBC recalculated the NPV on the basis of assuming an annual savings of \$790,000 compared to the previous value of \$590,000. The revised NPV calculation is attached as Appendix 34.2 (Exhibit B-2, BCUC 2.34.2, pp. 12-13).

The Application also refers to the safety requirements promulgated by WorksafeBC (Application, p. 29) which require that the PIC of the network have before him/her a mimic display of the power system under control. The magnitude of the benefits of improved safety operations are difficult to assess but the institution of the Program

would provide the PIC with much better insight as to the status of the network and would bring FortisBC into closer compliance with the WorksafeBC Occupational Health and Safety Regulation, Part 19.19. There are also inherent operational cost savings here estimated at \$100 K, depending on the “number of outages and the number of crews working on the power system”.

The system analysis that will be possible once the substation upgrades have been made will also permit more detailed analysis of individual substation equipment such as transformers, their performance, temperature etc. This in turn will permit more efficient maintenance and as well, will better inform equipment replacement schedules and in result, postpone some capital expenditures (Application, p. 3).

The development of a larger central database at the FortisBC Data Centre is part of the Program. The database will be “fed” by the SCADA system, the power-quality metering system and the CMMS. However, it is not clear in the Application, the extent to which these inputs will be operational once the substation upgrades are completed or whether the statement in the Application (p. 37) is forward looking and will require further expenditure for full operational capabilities. For this reason, the Commission Panel is concerned that the totality of the anticipated system control upgrades may go well beyond what is included in this Application and could well involve significantly more capital expenditures. This in part, explains why the Panel believes that further monitoring of the Program is required.

However, the additional cost to link the two systems, CMMS to SCADA, would essentially be labour costs of approximately \$40,000. No significant additional hardware or software would be required (Exhibit B-5, BCUC 2.29.1, p. 1). The costs and benefits of extending remote control to distribution field devices would be identified in a future Capital Expenditure Plan filing (Exhibit B-5, BCUC 2.40.2, p. 24).

It is noted in the Application (p. 19) that the estimated benefits may be partially offset by increased operating expenses (e.g., for additional leased communications).

In the Application, there has been no attempt to assess possible risks, either to completion schedules, equipment obsolescence, or to estimated capital expenditures and possible overruns. Cost sensitivity analysis for labour and equipment price escalation was not attempted.

Commission Determination

The Commission Panel therefore accepts that new electronic technology is expected to meet the WorksafeBC requirements for safe operation. The Commission Panel also acknowledges that this Program is only the first step towards automation and that more benefits will be derived by providing a link into the CMMS and remote automation of devices external to the substations.

7.0 CAPITAL COST AND RATE IMPACT

The Program Capital Costs were reviewed and except for the data link to the CMMS and the remote automation of devices, the estimate was complete for the proposed scope.

Commission Determination

The Commission Panel therefore accepts FortisBC's estimate of \$6.38 million as proposed in Exhibit B-1, page 21.

8.0 DEPRECIATION RATE

The program depreciation rates and allocation of costs as between O&M and Capital were reviewed and modified in response to BCUC IR No.2. In response to BCUC IR No.2, the Depreciation Rate – composite average Appendix 1 – Revenue Requirements Analysis, line 63 was changed from 10 percent (Exhibit B-1, p. 39) to 6 percent in [Exhibit B-5, 2.44.1(b)]. Replacement assets from Appendix A26.5 were included. The majority of Program assets have about a 20 year life or a depreciation rate of 5 percent. Some Program assets have about a 20 year life or a depreciation rate of 10 percent, while other Program assets have about a five year life or a depreciation rate of 20 percent. Hence, the depreciation of 6 percent as an overall average is acceptable for this group of Program assets.

9.0 NET PRESENT VALUE OF REVENUE REQUIREMENT AND THE ONE-TIME RATE IMPACT

As a result of the modification of the program depreciation rates and allocation of costs as between O&M and Capital in response to BCUC IR No. 2, the Net Present Value of Revenue Requirement is \$4.516M and the one-time Rate Impact is now 0.18 percent [Exhibit B-5, 2.44.1(b)]. Replacement assets from Appendix A26.5 were included.

10.0 INTERVENOR SUPPORT AND CPCN APPROVAL

In its Argument, BCOAPO does not oppose the Application and submits that the Program appears to provide an overall net benefit to customers. In his Argument, Mr. Wait does not oppose the application and submits that the Program would provide operating and improved system information benefits to the ratepayers. Mrs. Goodman's submission does not oppose the Application and she states that the Program should be approved. The Electricity Policy Branch of Ministry of MEMPR did not submit any argument.

Commission Determination

The Commission Panel therefore grants a Certificate of Public Convenience and Necessity for the Program as set out in the Order.

An Application by FortisBC Inc.
for a Certificate of Public Convenience and Necessity
Distribution Substation Automation Program

PROGRAM REPORT FORMAT

SEMI-ANNUAL PROGRESS AND FINAL REPORT

1. Program Status

- 1.1 General Program Status
- 1.2 Major Accomplishments, Work Completed and Key Decisions Made
- 1.3 Program Challenges and Issues; Issues Currently Open, Date Opened, Dated Closed, Those Issues that are Past Due
- 1.4 Plans for Next Period
- 1.5 Site Photographs (if useful)

2. Program Earned Value

- 2.1 Program “S” Curve showing the budget at completion, earned value, actual cost to date, planned value, estimate to completion, estimate at completion, cost variance, schedule variance, cost performance index, schedule performance index, status (average of cost performance index and schedule performance index). All values are to be shown throughout the duration of the Program.

3. Program Schedule

- 3.1 Program Milestone Summary Table with the planned finish date, actual finish date, variance in days, status
- 3.2 Procurement Summary with the planned finish date, actual finish date, variance in days, status
- 3.3 Contract Summary with the planned finish date, actual finish date, variance in days, status
- 3.5 Schedule Summary
 - 3.5.1 Schedule Performance to Date
 - 3.5.3 Schedule Difficulties and Variances
- 3.6 Scope Change Summary with Description of Request, Explanation for Request, Request Amount, Approved Amount, Deferred Amount, Reject Amount, Under Investigation Amount

4. Program Costs

- 4.1 Program Cost Summary including explanation of variances
- 4.2 Financial Summary including explanation of variances

5. Program Resource Management

- 5.1 Engineering & Construction Resources (Manhours, Planned vs. Actual – non-cumulative) both in chart and table format. Provide explanation for variance and corrective action taken.

6. Program Risks

- 6.1 Program Risks including Risk Description & Explanation, Date Risk Originated, Date Risk Last Reviewed, Level/Severity of Risk, Mitigation Plan, Contingency Plan, Mitigation Cost Amount (including schedule delay), Contingency Reserve Amount Required, Total Contingency Reserve Required to Date, Contingency Reserve Remaining.

POST PROGRAM IMPLEMENTATION REVIEW

1. Performance against Objectives and Outcomes
Describe the actual performance of the Program against planned in relation to the achievement of objectives, outcomes and target outcomes.
2. Performance against Outputs
Describe the actual performance of the Program against planned in relation to the delivery of outputs.
3. Performance against Budget
Describe the actual performance of the Program against planned in relation to the Program budget.
4. Performance against Schedule
Describe the actual performance of the Program against planned in relation to the Program schedule.
5. Lessons Learned
 - 5.1 What worked well?
Describe the Program management and quality management processes that were perceived to be appropriate and/or effective for the Program
 - 5.2 What could be improved?
Describe the Program management and quality management processes that were perceived to be inappropriate and/or ineffective for the Program, as reflected by the stakeholders and the Program records/documentation.
6. Conclusions
 - 6.1 Provide a summary of the conclusions drawn throughout the Report.

ANNUAL PROGRAM EFFECTIVENESS REPORTS

(Commencing 2008 for the Program duration and will be incorporated into the Revenue Requirement proceedings until F2015)

1. Direct reliability improvements (i.e. reduction in SAIDI, MAIFI, SARFI and CAIDI)
2. Reduction of travel costs (reduced crew vehicle usage)
3. Safety improvements (timely notification of critical alarms)
4. Improved operating efficiency (reduced recloser tagging costs)
5. Identification of reduction system losses and peak demand by power factor improvement
6. A summary report of substation alarms, their outcome and response time
7. A report of the number of GNR permits issued by remote-control
8. A system loss analysis report