Tab 9

2005 Capital Plan

Appendices

Appendix 1

Project Name: 2005 Head Gate Re-build Program

Cost: $2.48 million

Executive Summary

The projects under this program will address the main recommendations and limitations identified in recent condition assessments. During these projects, the gates, gate guides and embedded parts (where applicable) will be inspected and necessary repairs will be made. The gates will be structurally repaired, blast-cleaned and a corrosion control coating applied. The 2005 projects will address four pairs of head gates: the Corra Linn Unit 1, Unit 2 and Unit 3 head gates and the Lower Bonnington Unit 1 head gates. This program has been in place since 2000 and head gate rebuilds have been performed on four other FortisBC generating units and on all three units at the Brilliant Plant.

Background

Head gates are a critical safety component of a generating unit, in terms of both worker and plant safety. When maintenance is performed on a generating unit, the unit is taken off-line and the tailrace and head gates are lowered to block the water supply to the turbine. This isolates the generating unit from its energy source. The gates are the primary safety barriers for workers performing the maintenance work. In addition, in the day-to-day operation of the generator, the head gates act as part of the safety mechanism for the unit. If the unit experiences an over-speed runaway condition, the head gates will automatically close under full-flow conditions to cut off the water supply to the turbine and to trip the unit off-line.

The Lower Bonnington Plant was constructed in 1924 and the Corra Linn Plant was constructed in 1932. Each plant was constructed with three generating units, and each generating unit is equipped with two head gates. The life expectancy of head gates is 50 years; thus, the gates have exceeded their anticipated operating life by 20 to 30 years.

Two evaluations of the FortisBC head gate population have been conducted recently. An inspection of the Corra Linn Plant head gates was performed by ACRES International Limited (ACRES) in 1996, and a general condition assessment of the entire FortisBC head gate population was completed in 2000 by AGRA Monenco Inc. (AGRA). The 2000 assessment involved an inspection of the above-water components of the head gates, while a video camera was used to observe and record the underwater parts of the gates, the gate slots and the embedded parts. The assessment was comprised of: visual inspection of the gates, supporting structure, electrical and mechanical hoist components; an evaluation of the structural integrity of the gates and support frame; and an assessment of the ability of the gate to close under full flow conditions.

Both evaluations identified that advanced corrosion had the potential to compromise the function of the head gates. The recommendations included replacement of key structural components and membranes, and comprehensive corrosion abatement and re-coating.

On the strength of the evaluations, a series of head gate maintenance projects were started. The head gates on South Slocan Plant generating Unit 2 were the first FortisBC plant head gates to be rebuilt (in 2002), and have been followed by the recent rebuilds of the Upper Bonnington Plant generating Unit 5 and Unit 6 head gates.

The purpose of these projects is to:

- Maintain the life of the gates for a further 50 years
- Isolate the gates for future inspections
- Ensure the gates can be fully closed
- Re-establish the corrosion resistance of the gates
- Maintain safety of plant and personnel
- Increase the reliability of the gates
- Reduce the risk of equipment damage.

Project Cost Estimate

The cost of the first headgate rebuild project at each plant is greater than the subsequent head gate rebuild projects at the same plant. The first project carries the burden of equipment and preparation costs that are unique to each plant, and these costs are not re-incurred in the projects that follow. The Corra Linn Unit 3 Head Gate project was approved for $860,000 of which approximately $700,000 will be incurred in 2005. The Corra Linn Unit 1 and Unit 2 Head Gate projects are budgeted to be $613,000 and $612,000 respectively. The Lower Bonnington Unit 1 Head Gate project is budgeted at $570,000. The costs for Lower Bonnington are lower than Corra Linn because the Lower Bonnington head gates are 30% smaller by surface are than the Corra Linn head gates, and are more easily accessed.

It is anticipated that CPCN's will not be required for the rebuilding of the Lower Bonnington Plant Unit 1 head gates and the Corra Linn Unit 1 and Unit 2 head gates, with all projects being performed in 2005.

A CPCN application for the re-build of the Corra Linn Plant unit 3 head gates was submitted in 2000 and approved by Commission order C-1-01. This project will be performed in 2005.

Appendix 2

Project Name: Fault Level Reduction

Cost: $1.0 million for 2005, $1.0 million for 2006

Executive Summary

This project is required to reduce substation fault levels at various stations in the Kelowna area. High fault levels are a result of continued system expansion and without mitigation represent a safety risk to FortisBC employees and the general public. This substation project will address the most critical stations in 2005 and the remainder in 2006 for a total estimated cost of $2.0 million.

Background

Recent system analysis (subsequent to fault level analysis at Lee Terminal) has determined that fault levels on distribution busses at twelve of the Company's substations are greater than 150 MVA (standard for 13 kV system) and require immediate remedial action to reduce this safety risk.

These high fault levels exceed distribution equipment rating and could cause catastrophic failure of the equipment while the equipment is attempting to interrupt an electrical fault (short circuit) on the system.

Levels will increase with the completion of the present Kelowna Area Upgrade project that will add sub transmission capacity (138 kV) to the Kelowna area.

Stations affected by this project are listed in order of fault level where the 3 phase fault level or the single phase fault level exceed 150 MVA:

Table A 9.2

Station	3 Ph Fault (MVA)	1 Ph Fault (MVA)	Date
Lee Terminal (LEE) This station is being addressed by present station upgrade project.	438	173	2005
Westminster (WES)	182	217	2005
Recreation (REC)	260	265	2005
Glenmore (GLE) 2 busses	217	240	2005
DG Bell (DGB)	213	181	2005
Hollywood (HOL) 2 busses	202	216	2005
OK Mission (OKM) 2 busses	200	214	2006
Saucier (SAU)	199	217	2006
Huth (HUT)	168	196	2006
Sexsmith (SEX)	145	152	2006
Duck Lake (DUC)	142	150	2006
Playmor (PLA)	116	158	2006

The most economic method to mitigate the consequences of equipment failure due to excessive fault levels, is to install devices that limit fault current on the distribution feeders. These devices are known as current limiting reactors. Other methods include replacing station transformers with non standard high impedance units.

Options Considered

Option 1: Replace station transformers with high impedance units

Pros:

- Provides fault level control for entire station without auxilliary equipment installation.

Cons:

- Excessive cost (approximately $1.0 million per station).
- Introduces non standard equipment to the system.

Option 2: Add current limiting reactors to station busses or feeders

Pros:

- Least cost (on average $165,000 per station).

- Custom equipment sizing per station.
- Individual bus or feeder applications to minimize effect on the remainder of the station during a fault.

Cons:

- Complicated retrofit situations requiring customer outages.
- Minor additional station maintenance.

Financial Analysis/Assumptions Used

The option of replacing station transformers would cost an order of magnitude more than installing current limiting reactors and therefore is not considered for financial analysis. This project will be split over two years with 2005 portion of $1.0 million and 2006 of $1.0 million.

Option Selected

Option 2.

Implementation Process

Stations with greatest fault level will be done in 2005 (West Bench, Recreation, Glenmore, Bell, Hollywood) with the remainder in 2006.

Appendix 3

Project Name: Naramata Rehabilitation

Cost: $2.0 million in 2005 (project total $3.25 million)

Executive Summary

This project involves a complete station rebuild at a new site due to deterioration of the existing station and the lack of property at that site to accommodate customer load growth.

This Project is required to keep pace with the load growth in the area and to improve system reliability. A 63/13 kV, 20 MVA station will replace the existing 5.6 MVA station. An in-service date of November 2006 is planned to avoid risk of voltage problems during the winter of 2006/07.

Background

The Naramata substation has been identified as one of the legacy stations requiring rebuild due to condition of the equipment and station facilities. This rebuild must proceed in order to minimize outages and reduce risk of personnel injury and equipment failure. The Naramata substation is located in the east side of Okanagan Lake adjoining Penticton. Development in Penticton area has been generally weak during the last decade. However, load growth during the past two years has averaged nearly 4%, and steady load growth is expected to continue for several years due to the commercial growth in Penticton.

The substation needs excessive rehabilitation of the 63 kV switching facilities, 13 kV switchgear, station civil and station security.

- The substation switch structures and equipment structures have degraded to the point of being unsafe. They are mounted on timbers that have deteriorated and have shifted out of alignment creating a high-risk condition for switching failure. The present switching configuration results in inflexible operation.

- The station ground grid and security fence are substandard and in need of repair.
- Existing switching arrangement does not allow for proper switch maintenance.
- Existing 63 kV bus work does not meet present clearance standards.
- The mobile substation which is required for station maintenance and emergency supply, cannot be parked at the existing site and no further property can be acquired at existing site. A temporary site on Ministry of Transportation and Highways road allowance near Naramata substation site has been used for the mobile substation.
- Existing transformer tap changer has failed frequently as evident from customer voltage complaints and has reached end of life based on a recent maintenance inspection. The tapchanger is locked out of service to avoid catastrophic failure.
- Station Condition Assessment has identified auxiliary equipment structures such as the station service transformer as being unsafe and requiring immediate replacement.

Project Description

The project consists of a complete station rebuild at a new site due to lack of property for expansion purposes.

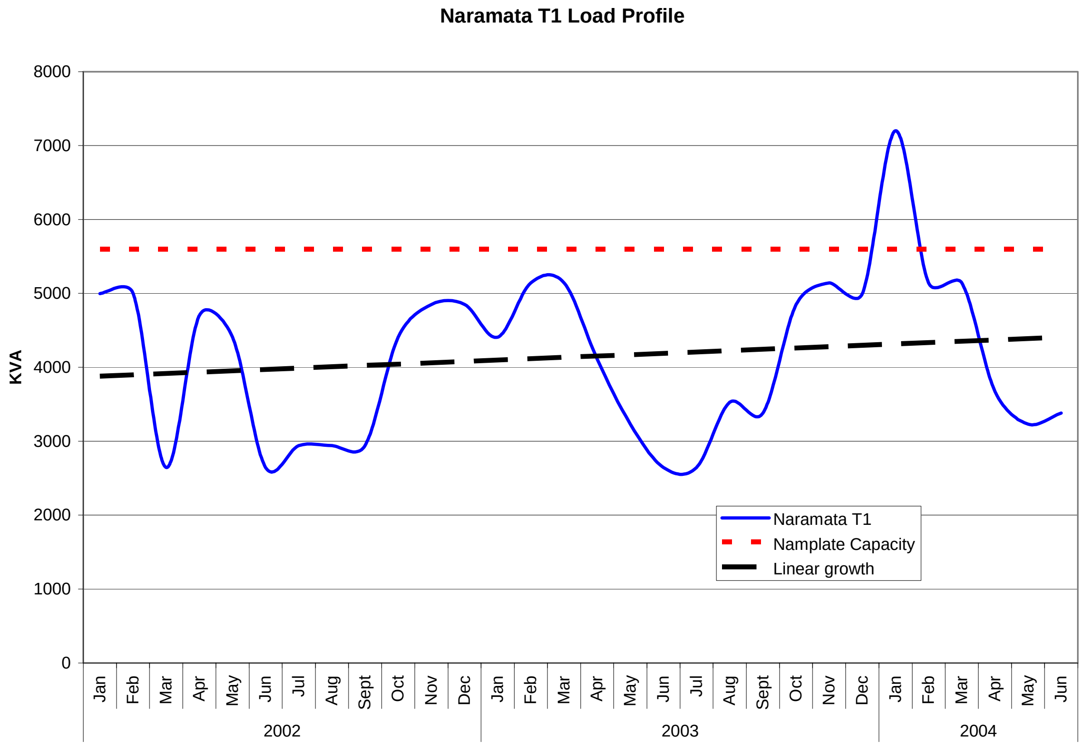
Engineering Design and Capacity

The new capacity of the substation (20 MVA), exceeds foreseeable load requirements for the next 15 years. The major project components are:

- A 63 kV / 13 kV, 20 MVA transformer
- 2 feeders at 13 kV with provision for third
- Control building to accommodate metering and communications

Capacity

The 2003/4 winter peak of 7200 KVA was 128% of nameplate rating (5600 KVA) for the Naramata T1 transformer. The chart below further demonstrates the positive growth in the past few years.



Options Considered

Option 1: Replace existing substation with a standard substation format including a larger transformer.

Pros:

- Efficient "greenfield" construction
- Compliance with safety standards

Cons:

- Higher cost

Option 2: Repair existing facilities

Pros:

- Lower cost
- Resolves safety issues (grounding)

Cons:

- Lack of property prevents mobile sub access for emergency backup and maintenance.
- Lack of property prevents abitlity to add feeders in future.

Financial Analysis/ Assumptions Used

Cost of the project assumes sufficient property can be acquired for $250,000.

Option Selected

Option 1 is selected. Option 2 does not provide capacity for anticipated future load growth.

Implementation Process

Installation is to be completed prior to winter peak 2006.

Risks

The condition of the equipment and grounding present a safety risk to personnel and the public.

There is a high risk of continued customer complaints due to poor voltage control as a result of failed equipment (transformer tap changer).

Appendix 4

Project Name: Transmission Line Rehabilitation

Cost: $3.4 million

Executive Summary

The project involves expenditures for structural stabilization of multiple transmission lines.

Included in the scope of work is replacement of cross-arms and poles, and apparatus replacements on structures according to the needs at each specific pole location. Also, there are some minor requirements in terms of insulator and guy wire changes and pole wraps. The total cost of the recommended work is estimated at 3.4 million.

Background

All of the rehabilitation projects are derived from the 2004 detailed patrol program. With 74 Line as an exception, this brings the transmission lines to year eight of an eight year patrol cycle. The patrol and rehabilitation cycle will start over again in 2005.

The 9 and 10 line projects are for stabilizing the line from Grand Forks to Mawdsley in Warfield. These lines must be kept in service for the next four to five years while the Boundary area development projects are completed.

The 18 Line (Waneta to Beaver Park) requires cross arm replacements.

The 25 Line (South Slocan to Brilliant switching station) requires structure replacements and rehabilitation due to realignment of the transmission line, clearance issues and bringing the line into legal compliance.

The 29 Line (South Slocan to Passmore to Graphite mine) requires rehabilitation on a de-energized section of the line. This existing line runs parallel to other transmission lines and must stay in good operating condition to avoid safety issues.

The 30 Line (South Slocan to Crawford Bay), 42 line (Oliver to Huth in Penticton), 43 Line (Oliver to Princeton), 43A Line (Hedley to Mascot Mine), and the 73 Line (Vernon to Kelowna) all require rehabilitation as part of the assessment and rehabilitation program cycle.

The up-to-date patrol data supports a broadly based program of remediation for 2005.

Options Considered

The key stakeholders in the present project are customers, property owners and the general public along the route of the subject lines. The customers' interests are related to reliability of service. are related to reliability of service. The property owners' and the general publics' interest 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.

Based on the inspections and patrols that have identified the condition of the lines, the available courses of action are as follows:

1. Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

2. Take measures to restore full service life to all structures requiring remediation.

The first course of action is not a legitimate planning option. Since FortisBC has conducted a condition assessment and is aware of certain deficiencies, it would be imprudent not to rectify the deficiencies.

The second course of action involves replacement or refurbishment of deteriorated structures and hardware. Specifically, all poles labeled as "reject" in the test data would be replaced, and all poles labeled as "stub" would be stubbed. All fix maintenance items would be completed.

Project Cost Estimate

The following table identifies all of the sub-level projects within the transmission line rehabilitation program:

Table A 9.4

Line #		Replace Pole Qty	Stub Pole Qty	Wrap Pole Qty	Fixes Service Truck Qty	Fixes Crew Qty	($000s) Total
9 & 10	Grand Forks to Mawdsley	15	37			129	500
18	Waneta to Beaver Park	1				7	50
19	South Slocan to Passmore to Slocan	71	12		11	107	900
25	South Slocan to Brilliant Switching Station	46				62	500
29	South Slocan to Passmore to Graphite Mine	5				25	100
30	South Slocan to Crawford Bay	26			10	72	500
42	Oliver to Huth (Penticton)	3					100
43	Oliver to Princeton	2		3		4	250
73	Vernon to Kelowna	16	11	2		66	500
Totals		**185**	**60**	**5**	**22**	**472**	**3,400**

These estimates were developed from the 2004 project cost analysis. The funds for this project are to acquire materials, engineering design patrol and rehabilitate the above lines in 2005.

A cost comparison was not completed for this business case because there are no viable alternatives to the proposed line stabilization project. No attempt has been made to quantify the benefits due to reliability improvements or to quantify the avoided property damage or public injury, although these factors form the strong argument for proceeding with this work.

Option selected

The second option is selected.

The proposed approach is consistent with FortisBC's strategic plan, in that it focuses on improving reliability, provides improvements in general public and employee safety and reduces the risk of public property damage while conforming with the long-term plan for Kootenay system development.

Appendix 5

Project Name: 32 Line Rebuild

Cost: $3.5 million

Executive Summary

The project involves expenditures for structural replacement of the 63 kV line, (32 Line) from Crawford Bay to Wynndel to AA Lambert Terminal station.

Included in the scope of work are replacement of cross arms, poles and all attached hardware for this line.

Similar to 44 Line (built in 1948) and 49 Line (built in 1949) which were rebuilt in the 1998 and 1999 respectively, 32 Line requires rebuilding because of poor condition of the structures. This line was built in 1951 and in the past four years, FortisBC has spent $1.3 million to rehabilitate sections of the line. This line continues to show failures even with this level of rehabilitation.

Background

The line was assessed for its condition in 2000. At that time, $300,000 was spent to repair urgent issues. The maintenance engineer completed an audit of the 2000 detailed patrol in April of 2003. The audit proved that the original patrol was no longer valid.

A detailed patrol of the line in the summer of 2003 showed that even though there has been recent rehabilitation work, there were three structures that required urgent restoration as their cross arms had failed. It was clear that this line was still in need of significant rehabilitation.

The line was then rehabilitated in 2003 for $400,000 and in 2004 for $600,000. During the past few years, consideration was being given to converting this line to 161 kV.

However, with the completion of the System Development Plan, a decision has been made to continue operating this line at 63 kV.

Options Considered

The key stakeholders in the present project are 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.

Faced with documentary evidence of the poor condition of the lines, the available courses of action are as follows:

Option 1: Do Nothing - take action only when the individual structures fail, i.e., Replace Upon Failure Option

The first course of action is not a legitimate planning option. Since FortisBC has been involved in a condition assessment program for the past six years, FortisBC is in the best position to know the condition of the line. Because FortisBC is aware of potential failures, FortisBC would be exposed to liability risk should 32 Line fail in any way and it results in damage to the public or to their property.

Option 2: Take aggressive measures to restore full service life to all structures requiring remediation, i.e., Four Year Stabilization Option

The second course of action involves structure selection to cover the entire four year test cycle, and the nature of the site-specific fixes is determined based on maximizing the service life of the structures. Specifically, all poles labeled as “reject” in the test data would be replaced, and all poles labeled as “stubbable” would be stubbed. All maintenance would be completed.

Option 3: Assess the condition of all the structures that have not been replaced in the last 20 years. Replace all structures that have any significant condition issues.

The third option considers that any structures that are older than 1984 must be strictly scrutinized for it's condition. This option considers the fact that there are many poles with top rot, shell rot and cross arm rot which are all very difficult to determine the remaining life. Considering that the average age of a line is 50 years, this line is due for an entire replacement.

Financial Analysis/ Assumptions Used

Cost for option 1 was not calculated because it is not a viable planning option.

Cost for option 2 is based on the expectation that the line will require the same level of rehabilitation as in the last four years for the next 20 years at $1.3 million each four years for rehabilitation and $100,000 per four years for detailed patrol. The cost for emergency repairs are in the order of $25,000 each year. NPV of revenue requirement is $2.586 million.

The cost for option 3 is $3.5 million. This estimate was developed from the historical cost of $7,500/structure to replace the structures in 2001, 2003 and 2004. NPV of revenue requirement is $2.504 million.

Option Selected

The third option is the chosen solution.

The proposed approach is consistent with FortisBC's strategic plan, in that it provides improvements in public and worker safety and reduced risk of public property damage while conforming with the long-term plan for Kootenay system development.

Other considerations

Conductor change for this line is not required. It is 2/0 ACSR and the condition is acceptable. However, the sag in this line is excessive in many places. This will have to be improved.

Appendix 6

Project Name: Computerized Maintenance Management System (CMMS)

Cost: $500,000 in 2005

$200,000 in 2006

Executive Summary

This project involves the purchase and installation of a computerized maintenance management system to improve the efficiency and effectiveness of FortisBC's maintenance program. An electrical equipment maintenance program is fundamental to assuring that the utility's apparatus operate in a safe and reliable manner. The trend in maintenance programs is towards condition based monitoring and predictive analysis prior to doing intrusive maintenance. An effective computerized maintenance management system is required to accomplish this. It is the backbone of the maintenance program. All analysis techniques, maintenance tasks and maintenance schedules are triggered from the management system.

The use of a "Computerized Maintenance Management System" makes the management system more efficient and effective. A CMMS will allow employees to be more aware of the condition of all equipment and use the equipment's condition to determine the level of maintenance or repair that is required.

The advantage of using a CMMS is that it will indicate the most effective time to address potentially failing equipment. Generally speaking, new equipment will be maintained less often and older equipment will be maintained more often, but only when it is required, not just because the time is due.

Background

Computerized maintenance management is standard in the electrical industry. It is fundamental to assuring that the utility's apparatus operate reliably by monitoring equipment conditions and predicting the type and timing of required maintenance to achieve the optimum life of the equipment. An effective management system tool is required to store the information and provide the predictive task assignments required to ensure cost effective and timely maintenance. Computerized tools such as this are the backbone of a good maintenance program. All analysis techniques, maintenance tasks and maintenance schedules are triggered from the management system.

FortisBC currently employs manual records and analytical processes to care for more than $200 million in substation assets. A management system is a tool that enables collection of equipment condition and it provides analytical capabilities to support a cost effective maintenance program; it better measures the condition of the asset, which is both more cost effective and provides for better system reliability. Repair, replacement or maintenance of equipment, based on its actual condition can be planned in the most cost effective manner.

FortisBC presently employs a first generation maintenance program that relies on rigid, periodic maintenance that does not reflect equipment degradation impacts on equipment. The current maintenance plan is developed utilizing only the technician's understanding of the system and it cannot easily adjust to changes in the system's operation. Maintenance plans based on individual experience rather than actual test and performance data tend to be inflexible and do not facilitate adjusting the maintenance schedule as conditions change. Virtually all industries requiring maintenance have found that moving from a time-based maintenance program towards predictive and preventative maintenance programs are more cost effective over the life of the apparatus. Utilization of a computerized maintenance management system will support these requirements.

The Western Electricity Coordinating Council (WECC) requires that all of its members must have a maintenance plan for all under-frequency load shedding equipment. This includes information such as:

1. Protection system identification
2. Summary of testing procedure
3. Frequency of testing

4. Date last tested

FortisBC is required to be in compliance with WECC's maintenance requirements to avoid sanctions. The implementation of a CMMS would assist FortisBC in becoming compliant with the maintenance of the protection system.

System Benefits

It is difficult to quantify the value of reducing failures, the value of premature spending in the form of maintenance or capital investment, and the value of planned maintenance schedule vs. the value of unplanned repairs. Initially a CMMS may cause an increase in the cost of maintenance for the electrical system. Improved visibility of the condition of equipment will dictate when maintenance should occur on that piece of equipment; it may identify that the maintenance should happen more often than in the past. In fact, if the condition of the equipment is continuously reported that it is in poor condition, that piece of equipment would be maintained more often, not less. However, over the long-term, the cost of maintenance should decrease.

This project's justification stands on the merit that FortisBC must understand the condition of the equipment in order to effectively manage the risk of failing equipment. The existing equipment that FortisBC maintains continue to age and the risk of failure is increasing. FortisBC will be also installing additional pieces of equipment in the future which will require tracking and condition benchmarking to prevent failures. Without the support of a solid CMMS, managing this risk is extremely difficult.

Preventing failures creates value. To demonstrate this value, the prevention of a failure of one power transformer would save the Company in the order of $700,000. There are approximately 110 transformers in FortisBC's system, which are an average of 30 years old. The life cycle of a transformer is 40 years, so there is a good possibility that FortisBC will see failures in the next 10 years. Preventing 3-4 power transformer failures over the course of the life of the CMMS would pay for the cost of the system. Combine this with approximately 350 circuit breakers valued at approximately $150,000 each as well as all the other pieces of equipment, it is clear that only a few prevented failures justifies the cost of the CMMS at $700,000.

Lengthy customer outages also have financial impacts (i.e. in the year 2001, the Cascade transformer failure took out the town of Rossland and the ski hill for almost two days). Preventing failure improves reliability. Over the course of the past three years, FortisBC has experienced approximately ten substation equipment condition related outages. On average, these outages lasted approximately 12 hours. This affected, on average, approximately 20,000 to 30,000 customers each time. Of these failures, six of them may have been intercepted and prevented by a skilled technician or engineer with an effective management system. The failures were of a nature that they had some indications that there were problems. By using a CMMS, a skilled user could have identified additional tests, reported a failure trend, or made retest recommendations in shorter time periods.

Once the condition of the equipment is known, FortisBC can plan for repairs or replacement in a structured manner that minimizes service disruptions and costs. Reliability and safety will increase as a result of having the ability to predict when a piece of equipment may fail. Capital cost requirements are reduced when a replacement can be properly engineered and planned vs. an emergency replacement where any substitute that is a close match is accepted and installed.

Options Considered

Six different CMMS programs were considered: EMS (status Quo), Web World, Maximo, Power @ Work, Cascade and SAP-PM (4.0 and 4.6). Each of these programs was measured for its functionality, limitations, scalability, and costs.

It was determined that only two solutions (Cascade and SAP-PM) would satisfy all of FortisBC's requirements. Detailed functional analysis and financial analysis was only performed on Cascade and SAP-PM for this reason. High-level estimates for the alternative systems are provided for comparison purposes.

Cascade and SAP were identified as the preferred solutions for the following reasons:

1. Both systems have the same maintenance functionality.
2. Status Quo and Power@Work tend to focus more on work management than asset management.
3. Cascade's stand-alone capital requirements are the lowest.
4. SAP has the advantage of being fully integrated with the entire business solution.
5. Cascade has the advantage of being integrated with four other maintenance software systems that are being used by FortisBC.

Financial Analysis/ Assumptions Used

The analysis has been done with today's cost comparison. All non-financial benefits are measured as none, Low, Medium or High.

Table A 9.6.1
Financial Comparisons
($000)

	Operating Costs		Capital Costs			
	Training	Support	Licences	Implement	Procedures	Total
Cascade	100	25	175	400	125	**700**
SAP 4.6C	100	100	75	684	125	**884**
Status Quo	-	-	-	-	125	**125**
Web World	100	150	42	850	125	**1,017**
Maximo	100	150	180	900	125	**1,205**
Power @ Work	100	150	400	400	125	**925**

Table A 9.6.2
Non -Financial Comparisons

	Scalability	Maintenance Functionality	Business Interface	Remote Functionality	Maintenance Software Interface
Cascade	High	High	Low	High	High
SAP	High	Medium	High	High	Low
Status Quo	None	Medium	None	None	Low
Web World	Medium	Medium	Low	Medium	Low
Maximo	High	High	Medium	High	Medium
Power @ Work	Low	Low	Low	None	Low

Definitions

Scalability: A judgment of the ability of the software system to handle a greater volume of data. The requirement is to add equipment as generation, transmission and substation assets are upgraded.

Maintenance Functionality: The ability of the software system to perform maintenance tasks such as scheduling, triggering and data collection.

Business Functionality: The ability of the software to integrate with the business software, which is SAP 4.6C

Remote Functionality: The ability of the software to allow technicians to collect data while in the field and easily imports the data into central systems.

Maintenance Software Interface: The ability of the management software to integrate with existing maintenance software.

Option Selected

The assessment indicates that Cascade is the preferred alternative since:

- Cascade has the highest non-financial benefit
- Cascade has the lowest capital requirements
- Cascade has the lowest revenue requirements.

Appendix 7

Project Name: Kootenay Mobile Station

Cost: $2.0 million

Executive Summary

This project involves the purchase of a 20/24/30 MVA mobile substation with 63 kV primary and 13 kV/25 kV secondary, and breaker protection to replace the Kootenay 6.5 MVA mobile unit.

Background

The original Kootenay 6.5 MVA mobile unit was purchased in 1957. The 35-foot trailer bed has become deteriorated. Trucking firms refuse to haul the unit due to mechanical condition, and Fleet Services will no longer certify it road-worthy. The power transformer also acquired in 1957 is also in a state of advanced deterioration. As well, its use is limited because it is too small to handle most of the Company's substation or feeder loads. Existing secondary switching facilities (bulk oil filled) are unserviceable due to unavailability of spare parts which create a high-risk condition for protection coordination failure and switching failure. Existing secondary control and metering equipment is obsolete.

Options Considered

Option 1: Do nothing. Operate the existing mobile 6.5 MVA mobile.

Option 2: Use the existing transformer on a new platform and inststall new protection and switching. Replace transformer the next year.

Option 3: Salvage the existing mobile station and replace it with a new mobile station.

Financial Analysis/Assumptions Used

Option 1: No financial analysis is required.

Option 2: The estimated cost is $1.4 million in year one and $1.0 million in year two. The net present value (NPV) of revenue requirements is $1.723 million.

Option 3: The estimated cost is $2.0 million. The net present value of revenue requirements (NPV) is $1.382 million.

Option Selected

For Option 1, the do nothing option ignores the safety and reliability of the existing mobile.

Option 2 carries risk for the condition of the existing transformer.

Option 3 is the least cost option.

Option 3 is selected.

Risks

Safety – Condition of the mobile carries the risk of failure. This could expose the general public and employees to physical harm.

Compliance – Running the existing mobile would be illegal due to condition of the trailer assembly.

Reliability – The mobile stations are FortisBC's first line of defense against long term transformer outages in a station and are used for improved reliability for bypassing existing stations when they are being maintained.

Appendix 8

Project Name: Distribution Growth Capacity Increases

Cost: $5.17 million

Executive Summary

Normal load growth on the distribution system requires that capacity upgrades or additions to lines are implemented to provide acceptable standards of 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. In addition, projects are identified to provide sufficient redundancy to maintain acceptable levels of supply during planned and unplanned outages on the distribution system.

Background

The distribution feeder network is evaluated for capacity performance for the forecasted load growth in each of the service areas. Utilizing load models the network is tested for voltage, thermal loading, and backup capabilities for loss of supply. Where standards of service are not met, appropriate upgrade options are modeled and evaluated for performance improvement. The set of solutions used are load transfer, load balancing, regulation, shunt capacitors, re-conductoring, line additions, load splitting and new source locations. Growth capacity increase projects are not proposed for line extension to new load centers, but may cross un-serviced areas to provide a tie to an adjacent supply point if necessary.

For voltage, thermal loading, and short circuit level deficiencies a solution is selected from options described above to be implemented in the year prior to the emergence of the deficiency in the service standard.

Backup performance improvements are dependent on the nature of the service area. Typically supply arrangements are significantly different from rural to low density to high density urban centers. Rural areas usually have a single transformer supply point with 1 or 2 radial feeders. The feeders are expected to provide reciprocal redundancy, but failure of the single supply transformer will result in an outage until mobile transformation is installed. Distribution systems in high density urban centers, such as the City of Kelowna incorporate numerous multiple transformer supply points with many interconnected feeders. It is expected that each feeder, after normal manual switching operations, is provided backup from a combination of adjacent feeders and that failure of any one supply transformer can be backed up through a combination of local and remote transformation after normal manual switching of interconnected feeders.

In high density urban areas, two transformer substations are almost always loaded above the rating of a single transformer. The excess load is expected to be transferred to an adjacent transformer during maintenance or failure of one of the two transformers. In this way, transformer capacities are more highly utilized while still maintaining backup standards. As such, feeder ties and capacity increases, which are a much lower capital investment than transformer capacity increases, are preferred to maximize utilization of the existing transformation capacity.

As high density urban areas grow on their perimeters, economic reach of the existing supply points becomes limited as feeders extend beyond their economic reach to feed this load. Ultimately, new supply points are required at these new load centers. Feeders from existing supply points are first extended into those areas and will become part of the feeder network when the new supply point is built. This staged approach to development of a distribution network in this type of area provides optimum use of capital investment. This project includes several of these feeder extension projects, but the ultimate new supply points are described in separate projects.

Table A 9.8.1
Distribution Growth Capacity Project

Issue	Preferred Options	Cost ($000s)
Sexsmith Capacity	Duck Lake to Sexsmith Feeder Tie Complete GLE5-SEX2 Tie and Add GOLB	450 85
Quail Capacity	Quail development loopfeed	200
Dilworth Capacity	Dilworth development loopfeed	200
OK Mission/Glenmore Capacity	Extend OKM5 Feeder	600
Kelowna general tap thermal loading	General feeder protection upgrades	150
West Bench Feeder 1 Capacity	Voltage Regulator	85
Anarchist Mountain Capacity	Three phase 4.4 km of OSO2	350
East Osoyoos Capacity	New OSO4 Feeder to East Osoyoos	650
Baldy Supply	Convert Baldy Distribution and supply from Rock Creek at 25 kV	650
West Trail Voltage Conversion	West Trail voltage conversion completion	300
Passmore Feeder Capacity	Passmore Feeder 2 capacity increase	950
Small Capacity Issues	Small Capacity improvements	500
	TOTAL	**5,170**

Sexsmith Capacity Deficiencies

The load area in north Kelowna is currently fed from a single feeder (Sexsmith Feeder 1) and single transformer substation (Sexsmith). Both the feeder and substation are reaching their thermal limits, backup to both feeder and station are limited, and feeder end voltages are marginal. Sexsmith Feeder 1 has the highest demand and customer count of any single feeder in the FortisBC network. Growth in this area is now outside the typical supply radius of a Kelowna area substation and will require the development of a new source substation before 2008. In the interim, reduction of the load on existing facilities is required.

Option 1: Duck Lake to Sexsmith Feeder Tie

The Duck Lake substation is located approximately 10 km north of Sexsmith Substation. This station has a 28 MVA transformer and is under utilized. The open section between station feeders is approximately 4.5 km. The load currently serviced by the Sexsmith feeder is centered between the two sources. A 4.5 km feeder tie between Sexsmith Feeder 1 and Duck Lake Feeder 1 to transfer portions of Sexsmith Feeder 1 load to the underutilized Duck Lake substation would reduce loading on both Sexsmith Feeder1 and Sexsmith transformer, improve backup and improve the voltage in the area. When the planned future Ellison substation is completed, this feeder tie can form part of the feeder network in this area. (Cost estimate $450,000)

Option 2: Add Second Transformer at Sexsmith and install additional Sexsmith Feeder
Install a second 32 MVA transformer in the existing spare bay at Sexsmith, a fifth breaker termination and new distribution feeder to supply and split the Sexsmith Feeder 1 load area. This project would address the thermal loading on the existing Sexsmith transformer and Sexsmith Feeder 1.
(Cost estimate $2.2 million)

Option 3: Complete Glenmore Feeder 5-Sexsmith Feeder 2 Tie and Add GOLB
A City of Kelowna four lane project along Glenmore Drive will allow for completion of a short underground section to tie Glenmore Feeder 5 to Sexsmith Feeder 2. By including a switching point on Sexsmith Feeder 2, a transfer of load from Sexsmith to Glenmore substations can be made. This tie will not address the Sexsmith Feeder 1 capacity issue directly, but will provide some offloading of the Sexsmith source and provide feeder to feeder backup.
(Cost estimate $85,000)

Option Selected
Options 1 and Option 3. Ultimately, a new source substation is required 5-6 km north of Sexsmith as the load center moves in that direction. Increasing capacity at Sexsmith is not recommended due to it's increasing distance from the evolving load center. Sourcing the load in this area from Duck Lake will address the thermal loading issues for at least three years at which time the new north Kelowna substation is expected to be in service. The Duck Lake to Sexsmith tie option utilizes unused capacity from Duck Lake, and will offer a means of load transfer between Sexsmith and the future north Kelowna substation (Ellison) and Duck Lake thereby forming part of the ultimate feeder network.
Completing the Glenmore Feeder 5 to Sexsmith Feeder 2 tie is a cost effective means of adding further load transfer capabilities in this part of the network.

Quail Development Capacity Deficiency

The Quail Ridge development in north central Kelowna is growing at a rate which will exceed the capacity of the existing radial underground supply in several years. A failure on the underground system would result in extensive restoration delay. Reduction of the load on existing facilities is required.

Option 1: Quail Development Loopfeed

Install a second supply into the area and split the existing load with a tie point.
(Cost estimate $200,000)

Option 2: Increase capacity of existing tap.

Replace the existing #2Cu underground supply with 350AL.
(Cost estimate not completed due to options inadequacy to address distribution planning guidelines for system backup of underground systems)

Option Selected

Option 1 is selected based on its ability to reduce thermal loading on the existing tap while also offering backup capacity.

Dilworth Mountain Development Capacity Deficiency

The Dilworth Mountain development in central Kelowna is growing at a rate which will exceed the capacity of the existing radial underground supply in several years. A failure on the underground system would result in extensive restoration delay. Reduction of the load on existing facilities is required.

Option 1: Dilworth Mountain Loopfeed

Install a second supply into the area and split the existing load with a tie point.
(Cost estimate $200,000)

Option 2: Increase capacity of existing tap.

Replace the existing #2Cu underground supply with 350AL.

(Cost estimate not completed due to options inadequacy to address distribution planning guidelines for system backup of underground systems)

Option Selected

Option 1 is selected based on its ability to reduce thermal loading on the existing tap while also offering backup capacity.

OK Mission/Glenmore Capacity

Load growth in the OK Mission Feeder 4 and Glenmore Feeder 1 areas is limiting both capacity and backup capabilities of these two feeders and sources. These two feeders supply an area between KLO and Springfield Roads having a high density residential, commercial and institutional customer load base including the Landmark towers development. Continued high levels of growth are forecast for this supply area. Transformer backup at Glenmore is limited and requires either additional load transfer capability to remote stations or increased station capacity.

Option 1: Extend OK Mission Feeder 5, Tie to OK Mission Feeder 4, Extend to Springfield Road tie to Glenmore Feeder 1. OK Mission Feeder 5 currently is used as a wholesale supply point for the City of Kelowna municipal electric system. Load on this feeder is currently at 50% of capacity. The remaining capacity can through extension of the feeder be utilized for thermal reduction on OK Mission Feeder 4 and provide backup supply to both OK Mission Feeder 4 and Glenmore Feeder 1. This will require extending OK Mission Feeder 5 underbuild along Richter to Springfield, then along Springfield to Burtch where it will tie into Glenmore Feeder1. In addition, a tap will be built off this extension along Guishachan Roadd to provide a backup into the Guishachan load area for further capacity improvements.

(Cost estimate $600,000)

Option 2: New OK Mission Feeder 6 and tie to Glenmore Feeder 1

This option requires the a new termination and feeder (OK Mission Feeder 6) be built out of OK Mission substation and terminate at Glenmore Feeder 1 at the intersection of Springfield and Burtch Road.
(Cost estimate $1.0 million)

Option Selected

Option 1 is selected based on the ability to provide adequate load reduction on OK Mission Feeder 4 and backup capabilities to offload Glenmore Feeder 1 and Glenmore station source.

Kelowna Area General Tap Thermal Loading

As load steadily increases on feeders in the Kelowna area, fuse sizes on feeder taps have increased accordingly. Overloading and mis-coordination of fuses with upstream devices has become an increasing problem. Typically, it is expected that load studies will capture these deficiencies in advance; however, unpredictable load patterns can emerge with resultant protection issues.

Option 1: Kelowna General Feeder Protection Upgrades
Protection can be improved by reducing phase loading or applying three phase electronic protection.
(Cost estimate $150,000)

Option 2: Continue to increase fuse sizing on taps.

Option Selected

Option 1 due to Option 2 being unacceptable.

Option 2 is unacceptable as reliability diminishes and ultimately safety is compromised as upstream sensitivity to faults diminishes.

West Bench Feeder 1 Capacity

Voltages at end of feeder are expected to be below minimum voltage levels by 2006.

Option 1: Install Voltage Regulation
(Cost estimate $85,000)

Option 2: Re-conductor 2.2 km to 477AL
(Cost estimate $250,000)

Option Selected

Option 1. Selected due to lower capital cost. Re-conductoring is not considered in this case as thermal loading level of existing 2/0 is acceptable.

Anarchist Mountain Capacity

A single phase tap currently supplying the Anarchist Mountain area is excessively loaded, causing voltage and protection issues. The area is showing strong load growth patterns adding to the current capacity problems.

Option 1: Three Phase 4.4 km of OS-Ø2
Build a 4.4 km three phase 477AL alongside of the existing single phase Anarchist tap. Re-connect single phase taps to new line.
(Cost estimate $350,000)

Option 2: Feed Anarchist at 25 kV from Rock Creek
In this option, a 14 km section of single phase 25 kV line from Rock Creek to Bridesville is three phased and then extended for an additional 4 km to reach the Anarchist load area. A 25/13 kV step-down transformer must be utilized for the 13 kV Anarchist load area.
(Cost estimate $900,000 without capacity increase at Rock Creek substation)

Option Selected

Option 1 is selected at this time with future considerations to implement Option 2 when the Rock Creek source capacity is increased and it becomes viable to provide load transfer capability between Osoyoos and Rock Creek. Option 1 will provide long term capacity support to the Anarchist Mountain area. By three phasing with 477AL instead of smaller capacity conductor, the opportunity exists for future load transfer capacity between Rock Creek and Osoyoos.

East Osoyoos Capacity Deficiency

Load growth in east Osoyoos is exceeding the capacity of the single feeder currently supplying the area. Forecasts indicate that the feeder will be at its thermal limit within two years.

Option 1: New Osoyoos Feeder 4 to East Osoyoos

This option requires a station termination with breaker and a second feeder with 477AL conductor from the west Osoyoos substation across the Osoyoos lake causeway to Lakeshore Drive. The load in east Osoyoos would be split between the two feeders. Both of the feeders would form part of the area feeder network and provide load transfer capability when an East Osoyoos substation is built.
(Cost estimate $650,000)

Option 2: No feasible alternative

Option Selected

Option 1 is the single available solution to address the shorter term capacity concerns in east Osoyoos. The longer term capacity requirements of the east Osoyoos area require the addition of a source substation and ultimate interconnection with the Boundary area at 25 kV.

Baldy Distribution Supply

The Baldy distribution system is a 2.4 kV delta system supplied by the Baldy substation. Modern distribution supply convention does not promote delta connected systems because of the lack of capability to detect and isolate faults. The Baldy substation is below acceptable standards and should be either rebuilt or abandoned.

Option 1: Re-build Baldy Distribution to 14.4/25 kV grounded wye and supply from Rock Creek substation at 25 kV

The local distribution will be converted to standard 25 kV construction. This option is consistent with the new Kettle Valley Distribution Source project in the Boundary area. This new source would replace Rock Creek as the supply for the Baldy area.
(Cost estimate $650,000)

Option 2: Re-build Baldy Distribution to 14.4/25 kV grounded wye and rebuild Baldy Substation in close proximity to existing site.

Convert local Baldy town site distribution to standard 25 kV construction. Salvage and rebuild the local distribution source supply substation at or near existing site.
(Cost estimate is in excess of $4.0 million including both distribution line rebuild and distribution source substation).

Option Selected

Option 1 will provide adequate supply in the Baldy area for the forecast period. An additional source substation or location of a source substation at Baldy is not consistent with the Boundary region development plans.

West Trail Voltage Conversion

A multi-year project to convert the distribution systems in the Trail area is close to completion. A few remaining items remain outstanding and require attention including salvaging of the 2.4 kV West Trail Substation and it’s 63 kV supply line. Difficulties in re-servicing of the Trail arena and several other services with 13 kV primary have now been resolved and can proceed.

Option 1: West Trail Voltage Conversion Completion

Address remaining items in the Trail area to complete this multiyear project. (Cost estimate $300,000)

Option 2: Do nothing

Continuing to operate the existing substation to maintain a 2.4 kV supply to limited customers.

Option Selected

Option 1. Conversion of the remaining 2.4 kV primary services will allow the final salvage of an unacceptable West Trail substation.

Passmore Feeder Capacity

Passmore Feeder 2 has very limited capacity due to small conductor sizing and limited three phasing on the circuit. Voltage concerns were addressed in 2003 and 2004 with voltage regulation resulting in feeder voltage marginally above minimum planning limits. The heavily loaded single phase taps don't allow for fuse coordination with the station breaker resulting in widespread outages for localized faults.

Option 1: Passmore Feeder 2 Capacity Increase

Three phasing 2 kms of two phase 19 Line underbuild with and an additional 6 kms of single phase line sections. (Estimated cost $950,000)

Option 2: Passmore Feeder 2 Upgrade

Three phase 16 kms of single phase and an additional 0.8 km of 19 Line underbuild. (Estimated cost $1.48 million)

Option Selected

Option 1. Under-building 19 Line is a complex and costly process. Unfortunately the nature of the terrain in this area does not afford many options. Option 1 provides the least cost solution to the supply deficiency.

Small Capacity Increase and Improvements

Experience has shown that unforeseen load emergence will require capacity upgrades and voltage correction projects not accounted for in the capital plan. The projects include service upgrades, voltage regulation, tie to accommodate load splitting, single to three phase upgrades and conductor upgrades.

Option 1: Increase capacity as required
(Estimated cost $500,000)

Option 2: Do nothing

Option Selected

Not addressing unforeseen voltage, thermal loading, and protection safety issues is unacceptable. All issues as they are detected will be evaluated for most effective solution from options described.

Implementation Process

Projects described will be designed and constructed between January 1st and December 31, 2005. All projects will be managed to ensure adherence to quality, schedule and cost expectations.

Risks

If components of project as identified are not completed, the result will be non compliance to either or both voltage or thermal loading standards of service.

Thermal Loading

Standard distribution construction assumes that facilities will be operated at normal thermal limits. Exceeding this limit increases risks of clearance violation.

Voltage

Deviation from CSA recommended voltage levels at the customers' point of delivery will affect the designed operating characteristics of the customers' equipment. Probability of damage to customer equipment increases as the voltage deviation increases.

Appendix 9

Project Name: Vehicle Lease Buy-out

Cost: $2.74 million

Executive Summary

The Company has determined that it would be advantageous from a fleet management perspective to buy-out the lease of approximately 42 units in 2005. The lease buy-out would cost approximately $2.74 million and would reduce lease costs by a corresponding $975,000 per year. The transaction would yield a net decrease in revenue requirements in 2005 of approximately $800,000. The advantage decreases each subsequent year as the tax depreciation impact drops but will still yield a net decrease in requirements of over $600,000 in 2010 after which the units will likely have reached the end of their useful life.

Background

The decision as to whether to lease or purchase vehicles should be based on the net present value of the revenue requirements of leasing versus buying over the life cycle of the unit. The life-cycle of a typical fleet unit is in the order of seven to nine years. Factors that need to be included in the analysis include, capital cost, residual value, lease rate and the lease buy-out cost.

Purchasing fleet units will generally result in a lower revenue requirement on a life-cycle basis due to the tax shield associated with ownership in a regulated cost of service environment. The accelerated tax depreciation rate fully offsets the current book depreciation rate and partially offsets the cost of financing the purchase, reducing the impact on revenue requirements.

The revenue requirement calculation for the continuing lease option of the 42 units in question can be seen at Table A 9.9.1.

The revenue requirement calculation for the purchase option of these vehicles can be seen at Table A 9.9.2.

Table A 9.9.1

Revenue Requirements Template - 2005
VEHICLE LEASE

Line No.		NPV @ 10.00%	Year: Dec-05	1 Dec-06	2 Dec-07	3 Dec-08	4 Dec-09
	Summary						
	Revenue Requirements						
1	Operating Expense (Incremental)	**4,065,619**	975,000	975,000	975,000	975,000	975,000
2	Depreciation Expense	**0**	0	0	0	0	0
3	Carrying Costs	**0**	0	0	0	0	0
4	Income Tax	**0**	0	0	0	0	0
5	Total Revenue Requirement for Project	**4,065,619**	975,000	975,000	975,000	975,000	975,000
	Rate Impact						
6	Forecast Revenue Requirements		183,000,000	186,660,000	190,393,200	194,201,064	198,085,085
7	Rate Impact		0.53%	0.52%	0.51%	0.50%	0.49%
8	**NPV of Project / Total Revenue Requirements**		**0.57%**				
	Regulatory Assumptions						
9	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		9.78%	9.78%	9.78%	9.78%	9.78%
12	Debt Return		7.15%	7.15%	7.15%	7.15%	7.15%
	Capital Cost						
13	Fleet Purchases		0				
14			0				
15	AFUDC		0	0	0	0	0
16	Total Construction Cost in Year		0	0	0	0	0
17	Cumulative Construction Cost		0	0	0	0	0
18	Land						
19	Net Cost of Removal						
20	Total Capital Cost in Year		0	0	0	0	0
21	Cumulative Capital Cost		0	0	0	0	0
	Annual Operating Costs / (Savings)						
21	Annual Cost Savings (line losses or other savings)	0	0			0	0
22	Annual Maintenance Savings	0		0	0	0	0
23	Property Taxex - Incremental	0	0	0	0	0	0
24	Total Incremental Operating Costs (Savings)		0	0	0	0	0
	(Forecast inflation rate 2%)						
	Depreciation Expense						
25	Opening Cash Outlay		0	0	0	0	0
26	Additions in Year		0	0	0	0	0
27	Cumulative Total		0	0	0	0	0
28	Depreciation Rate - composite average		2.00%	2.00%	2.00%	2.00%	2.00%
29	Depreciation Expense		0	0	0	0	0
	Net Book Value						
30	Gross Property		0	0	0	0	0
31	Accumulated Depreciation		0	0	0	0	0
32	Net Book Value		0	0	0	0	0
	Carrying Costs on Average NBV						
33	Return on Equity		0	0	0	0	0
34	Interest Expense		0	0	0	0	0
35	AFUDC		0	0	0	0	0
36	**Total Carrying Costs**		0	0	0	0	0
	Income Tax Expense						
37	Combined Income Tax Rate		35.62%	35.62%	35.62%	35.62%	35.62%
	Income Tax on Equity Return						
38	Return on Equity		0	0	0	0	0
39	Gross up for revenue (Return / (1- tax rate)		0	0	0	0	0
40	Income tax on Equity Return		0	0	0	0	0
	Income Tax on Timing Differences						
41	Depreciation Expense		0	0	0	0	0
42	Less: Capital Cost Allowance		0	0	0	0	0
43	Total Timing Differences		0	0	0	0	0
44	Gross up for tax (Total Timing Differences/(1-tax rate))		0	0	0	0	0
45	Income tax on Timing Differences		0	0	0	0	0
60	**Total Income Tax**		0	0	0	0	0
	Capital Cost Allowance						
61	Opening Balance - UCC		0	0	0	0	0
62	Total Cash Outlay		0	0	0	0	0
63	Subtotal UCC		0	0	0	0	0
64	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%
65	CCA on Opening Balance		0	0	0	0	0
66	CCA on Capital Expenditures (1/2 yr rule)		0	0	0	0	0
67	Total CCA		0	0	0	0	0
68	Ending Balance UCC		0	0	0	0	0

Table A 9.9.2

Revenue Requirements Template - 2005
VEHICLE PURCHASE

Line No.		NPV @ 10.00%	Year: Dec-05	1 Dec-06	2 Dec-07	3 Dec-08	4 Dec-09
	Summary						
	Revenue Requirements						
1	Operating Expense (Incremental)	**0**	0	0	0	0	0
2	Depreciation Expense	**571,272**	137,000	137,000	137,000	137,000	137,000
3	Carrying Costs	**757,741**	112,367	219,116	207,880	196,643	185,406
4	Income Tax	**(519,315)**	(121,945)	(252,953)	(139,946)	(61,731)	(7,869)
5	Total Revenue Requirement for Project	**809,698**	127,422	103,163	204,934	271,912	314,537
	Rate Impact						
6	Forecast Revenue Requirements		183,000,000	186,660,000	190,393,200	194,201,064	198,085,085
7	Rate Impact		0.07%	0.06%	0.11%	0.14%	0.16%
8	**NPV of Project / Total Revenue Requirements**		**0.11%**				
	Regulatory Assumptions						
9	Equity Component		40.00%	40.00%	40.00%	40.00%	40.00%
10	Debt Component		60.00%	60.00%	60.00%	60.00%	60.00%
11	Equity Return		9.78%	9.78%	9.78%	9.78%	9.78%
12	Debt Return		7.15%	7.15%	7.15%	7.15%	7.15%
	Capital Cost						
13	Fleet Purchases		2,740,000				
14			0				
15	AFUDC		0	0	0	0	0
16	Total Construction Cost in Year		2,740,000	0	0	0	0
17	Cumulative Construction Cost		2,740,000	2,740,000	2,740,000	2,740,000	2,740,000
18	Land						
19	Net Cost of Removal						
20	Total Capital Cost in Year		2,740,000	2,740,000	2,740,000	2,740,000	2,740,000
21	Cumulative Capital Cost		2,740,000	5,480,000	8,220,000	10,960,000	13,700,000
	Annual Operating Costs / (Savings)						
21	Annual Cost Savings (line losses or other savings)	0	0			0	0
22	Annual Maintenance Savings	0		0	0	0	0
23	Property Taxex - Incremental	0	0	0	0	0	0
24	Total Incremental Operating Costs (Savings)		0	0	0	0	0
	(Forecast inflation rate 2%)						
	Depreciation Expense						
25	Opening Cash Outlay		0	2,740,000	2,740,000	2,740,000	2,740,000
26	Additions in Year		2,740,000	0	0	0	0
27	Cumulative Total		2,740,000	2,740,000	2,740,000	2,740,000	2,740,000
28	Depreciation Rate - composite average		5.00%	5.00%	5.00%	5.00%	5.00%
29	Depreciation Expense		137,000	137,000	137,000	137,000	137,000
	Net Book Value						
30	Gross Property		2,740,000	2,740,000	2,740,000	2,740,000	2,740,000
31	Accumulated Depreciation		0	(137,000)	(274,000)	(411,000)	(548,000)
32	Net Book Value		2,740,000	2,603,000	2,466,000	2,329,000	2,192,000
	Carrying Costs on Average NBV						
33	Return on Equity		53,594	104,509	99,150	93,790	88,431
34	Interest Expense		58,773	114,607	108,730	102,853	96,975
35	AFUDC		0	0	0	0	0
36	**Total Carrying Costs**		112,367	219,116	207,880	196,643	185,406
	Income Tax Expense						
37	Combined Income Tax Rate		35.62%	35.62%	35.62%	35.62%	35.62%
	Income Tax on Equity Return						
38	Return on Equity		53,594	104,509	99,150	93,790	88,431
39	Gross up for revenue (Return / (1- tax rate)		83,247	162,332	154,007	145,682	137,358
40	Income tax on Equity Return		29,653	57,823	54,857	51,892	48,927
	Income Tax on Timing Differences						
41	Depreciation Expense		137,000	137,000	137,000	137,000	137,000
42	Less: Capital Cost Allowance		411,000	698,700	489,090	342,363	239,654
43	Total Timing Differences		(274,000)	(561,700)	(352,090)	(205,363)	(102,654)
44	Gross up for tax (Total Timing Differences/(1-tax rate))		(425,598)	(872,476)	(546,893)	(318,986)	(159,450)
45	Income tax on Timing Differences		(151,598)	(310,776)	(194,803)	(113,623)	(56,796)
60	**Total Income Tax**		(121,945)	(252,953)	(139,946)	(61,731)	(7,869)
	Capital Cost Allowance						
61	Opening Balance - UCC		0	2,329,000	1,630,300	1,141,210	798,847
62	Total Cash Outlay		2,740,000	0	0	0	0
63	Subtotal UCC		2,740,000	2,329,000	1,630,300	1,141,210	798,847
64	Capital Cost Allowance Rate		30.00%	30.00%	30.00%	30.00%	30.00%
65	CCA on Opening Balance		0	698,700	489,090	342,363	239,654
66	CCA on Capital Expenditures (1/2 yr rule)		411,000	0	0	0	0
67	Total CCA		411,000	698,700	489,090	342,363	239,654
68	Ending Balance UCC		2,329,000	1,630,300	1,141,210	798,847	559,193

Appendix 10

Project Name: Tools and Equipment

Cost: $711,000

Executive Summary

This project consists of a number of items. These are necessary to acquire proper tools and equipment required for the efficient and effective management of the generation and electrical system as well as the safety of workers and the public.

Background

General Tools and Equipment:

This involves the replacement of tools and equipment that have reached the end of their service life and the purchase of new tools that are better suited to the various trades from an ergonomic and safety perspective. These tools and equipment are maintained on a regular basis, however, over time they degrade and wear out, especially hot line equipment and rigging devices that must meet rigorous safety requirements. Ergonomic and safety concerns related to the difficulty of using certain types of cutting and compression hand tools is an industry issue and needs to be addressed. Where feasible such tools will be replaced with battery and hydraulic alternatives to improve working conditions and productivity.

The following items are examples of some tools to be purchased for 2005:

- Small electric hoists
- Gantry crane
- Hydraulic bolt cutters
- Hydraulic crimpers
- Rigging equipment

Test and Maintenance Equipment

This involves the acquisition of maintenance and test equipment for Telecommunications, Substations, Metering, and Line Operations and Generation for predictive, preventative and corrective maintenance activities.

As new equipment is deployed in the field it is necessary to purchase equipment that is suited to a wide range of needs from initial commissioning through to ongoing operations and/or maintenance. Testing equipment is used to verify the integrity and reliability of the equipment located in the substations and generating plants across the Company's service territory. The electrical equipment includes power generators, transformers, breakers, reclosers, voltage regulators, three phase pad mount transformers and step down transformers etc. Diagnostic testing and repair of the various types of equipment requires specialized tools and test equipment. Innovations in tools and test equipment often lead to diagnostic tools that result in less equipment failures. As well, normal deterioration and the inability to maintain obsolete test equipment require that some of these items be replaced at regular intervals.

The test equipment is the basic tools required to design, verify and maintain reliable operation of the electric power system and associated equipment. Employing the proper test equipment in the field will better equip the field technicians with the tools they need to effectively address power system concerns. The electrical and mechanical maintenance test equipment is required to ensure the integrity and reliability of the equipment located in the Company's substations and generation plants across its service territory.

The following items are examples of test equipment that will be purchased in 2005:

- Transformer Moisture in Oil Analyzer
- Transformer Oil Filtration Equipment
- Power Analyzer
- Noise Interference Analyzer
- "Gas-in Oil" Calibration equipment

- Optical Power Meter
- Thermo Scanning equipment