FortisBC Inc.
2005 Revenue Requirements Application,
2005-2024 System Development Plan and 2005 Resource Plan

140.0 Reference: Volume 2, p. 13

Prior to the completion of the first 230 kV circuit between Vaseux Lake and Anderson Terminals, a planned or forced outage to any one of the Ashton Creek to Vernon 230 kV circuits requires that RAS be designed and armed to prepare for the next 230 kV line sequential double contingency.

Q140.1 How long will this arrangement be in effect?

A140.1 This RAS will be in effect until Vaseux Lake Terminal is upgraded for 230 kV operation in 2008. This RAS is to prevent the overloading of R.G. Anderson transformer T2 in case of the outage of both Ashton Creek – Vernon circuits or both Vernon-Lee circuits. In addition this RAS will also shed enough load in Kelowna to keep the loading on transformer T2 within its emergency limit. After the upgrade the function of this RAS will be limited to trip both Lee – Vernon circuits when both Ashton Creek – Vernon circuits are out so that the Vernon load is not supplied from Vaseux Lake Terminal.

Q140.2 How often does FortisBC expect the RAS will operate?

A140.2 The number of RAS operations is expected be very low if not zero. This scheme is only activated during periods when one of the circuits is out of service and would require a second outage event during this time to activate the scheme.

Q140.3 How many customers, and which major ones, would be affected by the operation of the RAS?

A140.3 The operation of the RAS will affect roughly 64,000 customers in the Kelowna and Penticton areas. The 14,000 customers in the Penticton area will be restored after a momentary outage to isolate the Kelowna loads.

The Kelowna system can then be sectionalized to serve roughly 25 percent of the load. This will leave approximately 50,000 customers exposed to rotating outages.

Q140.4 Should the RAS operate, what is the likely load restoration time?

A140.4 The restoration time after RAS operations is difficult to predict. The restoration time may be momentary if the system is automatically reconfigured to remove the contingency creating the concern. There may be rare occasions when the cause of the contingency is more permanent requiring the load to remain off line until the equipment or lines have been repaired.

Q140.5 Is there an alternative build sequence that would avoid the need for the RAS and, if so, at what cost?

A140.5 There is no alternative until Vaseux lake Terminal is upgraded for 230 kV operation in 2008. Also see the response to BCUC IR1 Q140.1.

Q141.0 Reference: Volume 2, p. 17

Once Vaseux Lake is converted to 230 kV, a new terminal substation (Bentley) is required near Oliver to supply 11 Line east to Grand Forks at 161 kV and create a new 138 kV source to support the load growth in the Oliver-Osoyoos area.

What is the increase in capacity to Oliver-Osoyoos attributable to the construction of the Bentley terminal station? That is, what is the difference in capacity between the configurations shown in Figures 2.4.2 B and 2.4.2 C?

A141.0 The construction of the Bentley terminal will see an increase in capacity at the 138 kV level to accommodate the Oliver-Osoyoos area growth. The increased capacity of the 138 kV system will be approximately 80 MVA.

142.0 Reference: Volume 2, p. 20

The Kelowna area structure maintenance program has not been able to keep up with the eight year test cycle and many structures identified as being in poor condition have remained in service out of necessity, or repairs have been rolled forward into future years leading to an ever-increasing backlog of required structure replacements.

Q142.1 Why has the maintenance program not been able to keep up with the eight year test cycle?

A142.1 The program uses an eight-year patrol and test cycle and the scope of the work was established using an estimated 2 percent pole replacement and structure stabilization requirement. The actual inspections identified a requirement for more than the estimated 2 percent replacements. Subsequently the company could not keep abreast of the requirements.

Q142.2 What are the risks associated with not keeping up with the maintenance program?

A142.2 There are several risks associated with not keeping the maintenance program up to date.

1) A second or third patrol would be required over the course of the eight-year cycle to ensure that the issues that are prioritized at a lower level are not becoming a critical hazard.

2) The annual patrol for these lines would be more specific and take longer.

3) There is potential for more outages.

Safety is still key, so FortisBC prioritizes the conditions of the structures based upon, safety, compliance and reliability. All safety issues are dealt with before addressing reliability and compliance issues.

Q142.3 What is FortisBC proposing to address this specific issue?

A142.3 FortisBC is at the seventh year of an eight year rehabilitation cycle for the distribution system and at the eighth year of an eight year cycle for the transmission cycle. Because Fortis began assessment of the worst performing distribution feeders and the oldest transmission lines, the trends for the condition of the line is improving. This allows FortisBC to review lines that have been partially rehabilitated and address the lower priority issues from the previous assessments.

Q142.4 Which other maintenance programs in this area, if any, been unable to keep up with the test cycle?

A142.4 Please refer to the response to BCUC IR1 Q65.3 and BCUC IR1 Q67.2 through BCUC IR1 Q67.5

143.0 Reference: Volume 2, p. 27

An alternate supply is required to provide a back-up for Summerland, Trout Creek and West Bench loads that are radially fed from the Huth substation.

Q143.1 Are reliability statistics available for these loads?

A143.1 The project to back up these areas has not been scheduled until 2010. This is to allow adequate time to assess the impact of other projects scheduled over the next 5 years to ensure the project is still required.

Reliability statistical calculations (i.e. SAIDI) are not available on an individual transmission line basis. However, there have been seven forced transmission outages greater than one minute on 49 Line affecting these loads since 1995. Outage information for the seven forced outages on the radial transmission line to these communities is shown in the table below:

Forced 49 Line Outages > 1 Min since 1994

Cause	Out Date	Minutes	Direct Cust	Direct Cust-Hrs	Indirect Cust	Indirect Cust-Hrs
POLE FIRE	1995-07-21	95.23	1,291	1,307.584	11,022	7,152.69
CROSSARM	1996-07-17	141.08	1,312	2,007.014	8,583	11,696.06
STRUCTURE	1997-09-14	597.25	863	1,406.358	4,836	48,138.35
PROTECTIVE RELAY	1998-04-20	18.57	874	270.454	4,836	1,496.47
CONDUCTOR	1998-06-10	95.42	874	1,389.903	4,836	7,690.58
HUMAN ERROR	1998-08-12	27.23	1,682	399.645	12,330	2,197.09
TREE INTO LINE	2003-10-28	85.73	991	1,416.029	4,836	6,910.11

Q143.2 If so, how do they compare with system-wide statistics and what is their long-term trend?

A143.2 These statistics are comparable to other radial transmission lines in the Okanagan. With an alternate supply the restoration time will be reduced for transmission outages one minute and greater which would improve the reliability statistics. Outage details for 45L are shown below for comparison.

Forced 45 Line Outages > 1 Min since 1994

Cause	Out Date	Minutes	Direct Cust	Direct Cust-Hrs	Indirect Cust	Indirect Cust-Hrs
INSULATOR	1994-03-03	35.27	1,462	859.331	4,273	180.42
SNOW UNLOADING	1994-05-01	1.52	1,462	36.956	4,273	108.01
LIGHTNING	1994-09-02	1.83	1,478	45.161	4,273	130.56
INSULATOR	1995-07-16	124.57	1,357	2,817.283	4,273	2,574.48
HUMAN ERROR	1995-08-04	171.18	1,357	3,871.596	4,273	354.90
HUMAN ERROR	1995-12-01	8.27	1,357	186.964	4,273	588.72
PROTECTIVE RELAY	2001-01-17	84.67	5,545	720.819	36,325	5,207.20
INSULATOR	2001-08-02	266.10	1,011	4,483.785	4,677	4,588.66

144.0 Reference: Volume 2, p. 27

The Naramata substation switch structures and equipment structures have degraded to the point of being unsafe. The station ground grid and security fence are identified by the condition assessment as in need of repair.

Q144.1 Do these problems constitute a risk to the public?

A144.1 The degraded equipment resides within the confines of the substation. The security fence is in place and does secure the site from the public, however it does not meet present height standards applied by FortisBC to new stations

Q144.2 What are the specific 2005 capital projects that are to address this problem?

A144.2 The Naramata Rehabilitation project as outlined in Volume1, Tab 9, Page 28 will address the problem.

Q144.3 Why was the substation allowed to deteriorate to the point of being unsafe?

A144.3 The "unsafe" conditions in the Naramata substation have been controlled through either equipment repair/replacement or the development of safe work procedures. These measures will ensure safe operation until such time as the station can be upgraded. Facilities upgrade work was minimized since a plan was in place to replace all legacy substations (1998 Master Plan) and Naramata was identified for completion in 2006. The project has now been advanced to 2005 due to increased load and a tap changer failure on the transformer. The additional load and need to repair the ageing transformer have advanced this rebuild to 2005.

145.0 Reference: Volume 2, p. 28

A previous project to upgrade to 49 Line has increased its capacity and reduced exposure to equipment failures as a main cause of line faults.

Q145.1 Are there any indications of line performance improvements since the upgrade?

A145.1 Major improvement work was completed in 1999, and since that time there has only been one forced transmission outage of greater than one minute. From the table below it is clear that outages greater than one minute have dropped significantly since completion of the improvement work, but momentary outages (less than one minute) continue to affect the customers served by 49 Line.

49 Line Forced Outages since 1994 (Includes Outages Less than 1 Minute)

Cause	Out Date	Minutes	Direct Cust	Direct Cust-Hrs	Indirect Cust	Indirect Cust-Hrs
POLE FIRE	1995-07-21	95.23	1,291	1,307.58	11,022	7,152.69
CROSSARM	1996-07-17	141.08	1,312	2,007.01	8,583	11,696.06
STRUCTURE	1997-09-14	597.25	863	1,406.358	4,836	48,138.35
PROTECTIVE RELAY	1998-04-20	18.57	874	270.45	4,836	1,496.47
CONDUCTOR	1998-06-10	95.42	874	1,389.90	4,836	7,690.58
HUMAN ERROR	1998-08-12	27.23	1,682	399.65	12,330	2,197.09
ANIMAL	1998-08-19	0.02	1,281	0.60	8,583	3.73
LIGHTNING	2002-06-18	0.03	951	0.53	4,836	2.69
TREE INTO LINE	2003-10-28	85.73	991	1,416.03	4,836	6,910.11
LIGHTNING	2004-08-25	0.03	1,118	0.62	4,836	2.69
Undetermined	2004-10-21	0.32	1,119	5.91	4,836	25.52

Q145.2 What are the overall reliability statistics for this area relative to other areas?

A145.2 The SAIFI statistic for the Penticton area (which includes 49 Line), which measures the number of outages greater than one minute that the average customer can expect to experience, has been worse than the company system average in 2003 and 2004. The communities of Summerland, Trout Creek, West Bench, Naramata and Westminster are all supplied by 63 kV radial transmission lines, which tend to be less reliable than areas that are supplied with dual radial or meshed transmission systems. Transmission and station projects such as the Vaseux terminal and the Huth Station rebuild project will specifically address the reliability issues in this area.

Q146.0 Reference: Volume 2, p. 29

An alternative to the Huth Station rebuild would involve eliminating the 49 Line termination at Huth and bypassing the substation to terminate 49 Line directly at Anderson Terminal, with Huth being reconfigured as a tapped 63/13 kV distribution source substation fed via taps from 52 Line and 53 Line. This simpler configuration would be a lower cost alternative, but would not provide the same flexibility and reliability as the full ring bus configuration.

What flexibility is lost with the lower-cost alternative?

A146.0 The ability to load share on a real time basis would be lost. As loads increase a ring bus allows for all lines to share the loads. The sharing will delay the need to add capacity to individual lines through capital line rebuilds.

Providing a ring bus at Huth substation will ensure an uninterrupted supply in a single contingency condition, as it will always remain connected to R.G. Anderson substation. If the ring bus is not completed the customers will continue to see interruptions due to single line outages and additional capital projects will be required to supply the increasing loads.

147.0 Reference: Volume 2, p. 30

Population centres such as Osoyoos are considered for loop fed transmission supply.

Q147.1 What are the specific transmission planning criteria for looping?

A147.1 There are no specific criteria for looping except for the relative size of the load. A second transmission line on an alternative route will provide more reliability.

Q147.2 Please provide FortisBC's transmission planning criteria.

A147.2 Both the bulk transmission (161 kV & 230 kV) and the sub-transmission (63 kV & 138 kV) systems are planned to meet the following criterion for all loading conditions.

- Normal operation; voltages are limited to ±5 percent of nominal voltage on the primary side of the major substation.
- Post-contingency; voltages are limited to ±10 percent of nominal voltage.
- Thermal loading on transmission lines is limited to 80 percent of the thermal rating as determined by seasonal ambient temperature conditions expected at the time of peak electrical load, and conservative conductor temperatures (80°C for ASC, 100°C for ACSR)
- Thermal loading is limited to 100 percent of the emergency rating as determined by the seasonal ambient temperature and an elevated permissible component temperature (100°C for ASC, 150°C for ACSR)
- The normal ratings of FortisBC transformers in summer and winter are 100 percent and 115 percent of nameplate rating respectively, while the emergency ratings for summer and winter are 125 percent and 135 percent of name plate rating.

Q148.0 Reference: Volume 2, p. 31

The existing transformers in the Osoyoos distribution source substation are both rated as condition 4 (immediate rehabilitation required) based on dissolved gas analysis. These transformers should be evaluated for their condition.

What further evaluation is required before repairing or replacing these transformers?

A148.0 Further investigation of the transformers is necessary to determine if replacement or rehabilitation is necessary. This will take place as part of the 2005 project "West Osoyoos transformer Rehabilitation" Volume 1, Tab 9, Page 41. In order to conduct the investigation the transformer will be de-energized, taken out of service, have the oil removed and an internal visual inspection will be completed. Other tests will be completed on various internal components and a final determination will be made on recondition or replacement based on the findings.

149.0 Reference: Volume 2, p. 36

A project will correct the historical misconnections of the transformers at Castlegar and Blueberry.

Q149.1 How did the misconnections arise?

A149.1 During the original construction of the Castlegar substation in 1968, proper phasing standards between the transmission system and distribution systems had not been clearly implemented. The ANSI standard was implemented in the late 1970s to address this issue.

Q149.2 What effect have the misconnections had on system operations?

A149.2 The distribution systems in the Blueberry/Castlegar area and the neighboring distribution systems in Trail and South Slocan cannot be paralleled due to the phasing issues that are currently present. This restricts the future level of distribution feeder backup possible in the Trail, Castlegar and South Slocan areas.