Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System

Part 2: Technical Requirements for Connecting Loads

Table of Contents

1. Introduction

1.1. Scope

This document specifies the general technical requirements for connecting a new (or previously isolated) load to the Alberta Interconnected Electric System (IES)[1] Transmission System[2]. It defines the requirements for all load facilities that will be directly connected to any IES Transmission Facility.

This document includes only the technical requirements specific to interconnection of load facilities. Any contractual, tariff, power pool, auxiliary services, operating agreements or other requirements to complete the interconnection are not in the scope of this document. For information on any commercial or tariff issues, contact the Customer Service Manager, ESBI Alberta Ltd.:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

Load Customers[3] wishing to connect a load at distribution voltages (25 kV or lower) should contact the appropriate distribution company, per the legislated distribution franchise areas.

1.2. Guiding Principles

The requirements specified in this document are based on the principles set out in the *Electric Utilities Act* (EUA)[4]. The Transmission Administrator advises Load Customers to become familiar with this document.

The EUA mandates the Transmission Administrator to create a “level playing field” for all persons seeking to connect any facilities to the IES. The Transmission Administrator's goal is to provide transmission access in the most effective, efficient and economic way possible while still maintaining the safety, reliability, security and integrity of the IES.

The Transmission Administrator shall interconnect facilities to the IES if the facilities satisfy the technical requirements described in this document and other terms outlined in the Transmission Administrator’s tariff. The Transmission Administrator will ensure that new load facilities do not jeopardize the reliability and security of the IES.

This document specifies the interface between the load facility and the IES, as well as the required information exchange between the facility owner and the Transmission Administrator. This document does not specify the design of equipment within the load facility.

[1] “Interconnected Electric System” as defined in the *Electric Utilities Act*, S.A. 1995, c.E-5.5. s.1(1)(p).
[2] “Transmission System” as defined in the *Electric Utilities Act*, S.A. 1995, c.E-5.5. s. 1(1)(ee).
[3] “Load Customers” means any eligible person (as that term is defined in *Electric Utilities Act*, S.A. 1995, c.E-5.5. s.1(1)(h)) seeking to interconnect loads to the Transmission System.
[4] *Electric Utilities Act*, , S.A. 1995, c.E-5.5.

1.3. The Interconnection Process

The Load Customer shall contact the Transmission Administrator's Customer Service Manager to request interconnection:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

The Load Customer should inform itself of the requirements in this document and prepare the appropriate information outlined in Section 2 below to expedite the interconnection process.

1.4. Definitions of Terms and Acronyms

For definitions of terms and acronyms not otherwise defined in this document, please refer to the Transmission Administrator Operating Policy (TAOP) OP-01. TAOPs can be reviewed on the Technical Documents page of the Transmission Administrator's internet web site: www.eal.ab.ca..

2. Description of the Load Facilities

The Transmission Administrator requires different levels of detailed information through the various stages of the project. Five discrete project stages are considered in this document:

1. Preliminary;
2. System Access Application;
3. Construction;
4. Commissioning; and
5. Commercial Operation.

Please Note: The technical information requirements listed in this document are intended to be comprehensive, therefore not all information will be relevant or necessary for every facility. The Transmission Administrator will work with prospective Load Customers to identify the specific information requirements for proposed facilities. Please contact the Transmission Administrator's Customer Service Manager to discuss further:

- **E-mail: customer-service@eal.ab.ca**
- **phone: (403) 232-0944**

2.1. Preliminary Information.

Prospective Load Customers who wish to have the Transmission Administrator assess possible load facility interconnections on a preliminary basis should provide the Transmission Administrator with the following information:

- desired point(s) of interconnection to the transmission system;
- estimated initial and ultimate peak demand;
- any identifiable large motors (500 kVA or greater) and the number of starts/hr or /day;
- any identifiable non-linear loads such as variable speed drives, arc furnaces, welders, static converters, etc;
- daily and annual load factor and shape;
- sensitivity to automatic and planned interruptions; and

- on site generation

2.2. System Access Application Stage

At the System Access Application Stage, prospective Load Customers applying for System Access Service should provide actual (where known), or best estimate, basic load data (Appendix A) and analytical modeling information (Appendix B) to the Transmission Administrator. In addition, the prospective Load Customer should contact the Customer Service Manager, ESBI Alberta Ltd. to identify any commercial information requirements. If Load Customers expect to interconnect any generating facilities to the IES, the Load Customer should refer to the document *Technical Requirements for Interconnecting Generators*[5].

2.3. Construction Stage

At the Construction Stage, the Load Customer should upgrade the information provided in Section 2.2 above to reflect the improved level of accuracy based upon more complete design and actual equipment ordered. Basic load data is specified in Appendix A and analytical modeling information is specified in Appendix B. In particular, at this stage the prospective Load Customer should provide:

- actual transformer and motor nameplate data;
- finalization of protection requirements;
- planned date to synchronize to grid; and
- startup power requirements.

2.4. Commissioning Stage

At the Commissioning Stage, the prospective Load Customer shall perform on-line tests to verify the estimated parameters provided earlier, and should provide the verified information to the Transmission Administrator to enable final acceptance. In addition, the prospective Load Customer should provide the Transmission Administrator with any changes in project scope resulting from actual construction. Specifically, at this stage the Load Customer should provide:

- adequate visibility to the System Controller;
- actual dates to perform testing and commissioning of large motors; and
- preliminary test results from commissioning tests.

2.5. Commercial Operations – Approved System Access Stage

After completing the commissioning tests, the Load Customer shall provide the Transmission Administrator with final testing, performance and validation reports. Assuming that the results are acceptable to the Transmission Administrator and the necessary commercial conditions are met, the Transmission Administrator will approve System Access Service and the facility will be able to enter Commercial Operation. After entering Commercial Operation the Load Customer should notify the Transmission Administrator of any changes in the technical information pertaining to the facilities.

---

[5] *Technical Requirements for Connecting to the Alberta Interconnected Electric System (IES) Transmission System, Part 1: Technical Requirements for Connecting Generators.*

The Load Customer should not unilaterally modify any control equipment parameters (e.g.: protection settings) without the Transmission Administrator's prior approval.

3. System Conditions at the Point of Interconnection

At the point of interconnection, the Load Customer can expect the following typical system conditions during system operations:

3.1. Voltage Level and Voltage Range

Typical operating voltages on the IES Transmission System vary within ± 10% of nominal voltage level. The voltage range at certain locations can be greater, especially during abnormal or emergency conditions.

3.2. Frequency and Frequency Range

The Alberta Interconnected Electric System operates nominally at 60 Hertz (Hz) Alternating Current (AC).

Loads connected to the grid that protect off-nominal frequency operation should have relaying protection that accommodates, as a minimum, underfrequency and overfrequency operation for the following time frames:

Underfrequency Limit	Overfrequency Limit	Minimum Time
60.0-59.5 Hz	***60.0-60.5 Hz***	***N/A (continuous operating range)***
59.4-58.5 Hz	60.6-61.5 Hz	3 minutes
58.4-57.9 Hz	61.6-61.7 Hz	30 seconds
57.8-57.4 Hz		7.5 seconds
57.3-56.9 Hz		45 cycles
56.8-56.5 Hz		7.2 cycles
less than 56.4 Hz	greater than 61.7 Hz	instantaneous trip

3.3. Power Quality

The IES Transmission System generally complies with industry standards and guidelines for power quality including but not limited to the following:

3.3.1. Voltage Flicker

The maximum permissible voltage flicker limits are defined in IEEE[6] Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

[6] The Institute of Electrical and Electronics Engineers, Inc.

3.3.2. Harmonics

Harmonic limits are as specified in IEEE Std 519-1992 “Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems”.

Upon request, the Transmission Administrator shall provide the Load Customer with information describing the specific harmonic-impedance envelope at the proposed point of interconnection.

3.3.3. Voltage Unbalance

The voltage unbalance on the electrical system under normal operating conditions may reach 3%. The voltage unbalance is calculated using:

$$\text{Unbalance (\%)} = \frac{100 \times \text{(deviation from average)}}{\text{(average)}}$$

as derived from NEMA[7] MG1-14.33.

3.4. System Grounding

The Alberta Transmission System is operated as effectively (solidly) grounded.

3.5. Network Protection and Control

Typical transmission protections consist of at least primary and backup protection systems for each protected element such as lines, transformers and busses. For lower voltage transmission systems, 69 kV to 138 kV, the backup protection can take the form or either local or remote protective relaying that operates only if the primary protection should fail or be unavailable. For higher voltage transmission systems, 230 kV to 500 kV, having a greater impact on overall system security, the backup relaying takes the form of a second, fully redundant primary protection. This second primary protection is capable of stand-alone operation in parallel with the first primary protection in a “one out of two” tripping scheme. Communication aided protection may be applied as well on the transmission system to allow coordination, high speed fault clearing and proper clearing of remote faults.

Reclosing relays are often employed with power circuit breakers to permit rapid restoration of service to a transmission line that has been isolated due to the detection of a transient fault condition. Automatic reclosing is appropriate to support continuity of service and to maintain stability of the interconnected system.

Most of the 230 to 275 kV class transmission lines and all of the 500 kV class transmission lines in the IES are equipped with single pole and three pole tripping as well as high speed automatic reclose facilities. This protection may have impact on the proposed load facility or may require modifications to accommodate the proposed facility. Such impact or modification requires careful consideration so that the proposed facility is not jeopardized, and the reliability of the transmission system is not reduced or compromised as a result of the addition of the facility.

[7] National Electrical Manufacturers Association

Three pole fault clearing with subsequent automatic three pole reclosing is usually implemented on all other transmission lines at transmission voltage levels.

3.6. Site Specific Information

In most cases the Transmission Administrator shall, on a best offers basis, provide the Load Customer with some or all of the following information for the proposed point of interconnection:

3.6.1. Reliability Indices

- Load interruption frequency;
- Expected duration of load interruption events;
- Total expected (average) interruption time per year;
- System availability or unavailability;
- Mean Time Between Failures (MTBF); and
- Mean Time To Repair (MTTR).

3.6.2. Fault Levels

The most recent three-phase and single-phase-to-ground short circuit infeed levels from the system at the interconnection point, including:

- The initial, forecast maximum future, minimum normal and minimum emergency fault current levels;
- Corresponding source reactance to resistance (x/r) ratios; and
- A clear definition of the power system conditions that were used to calculate the maximum and minimum fault levels and the x/r ratios.

3.6.3. Specific Voltage Level and Voltage Range

The anticipated minimum and maximum operating voltage range at the interconnection point under both normal and emergency conditions.

3.6.4. Remedial Action Schemes

A textual description of any site specific Remedial Action Schemes, including the following as a minimum:

- Purpose of the scheme;
- Input information to the scheme;
- Output (controls out) from the scheme;
- Functional logic of the scheme; and
- A functional level block diagram.

3.6.5. Network Protection and Control

- Protection standards;
- Range of clearing times for faults on connecting line(s);
- Protection design requirements;
- Reclosing time on connecting line(s);
- Reclosing details (single pole, three pole, conditional logic); and
- Information necessary to prepare relay settings of the supply line protections.

4. Interconnection Requirements.

The following sections describe the technical eligibility requirements for load facilities to interconnect to the IES. A Load Customer must comply with all the requirements of the Canadian Electrical Code Part I and The Alberta Electrical and Communication Utility Code (AECUC).

4.1. Point of Interconnection.

The Transmission Administrator will define the connection point in accordance with the EUA and the Transmission Administrator's Tariff.

4.2. Voltage Level Selection.

The following factors shall be considered when selecting the voltage level of the interconnection:

- Anticipated power demand of the complete facility;
- Maximum ultimate power demand of the complete facility;
- Reliability and configuration of the interconnection point prior to the interconnection and after the new required configuration is in place;
- The fault level required by the facility being connected in order to accommodate its power rating and motor starting requirements;
- The fault level contribution (if any) of the facility being connected and its impact on the surrounding region of the power system;
- The impact of harmonic current drawn by the load; and
- Economic considerations (transformer and other equipment costs, etc.).

4.3. Voltage Regulation and Power Factor Requirements.

The entire load facility, regardless of load composition (rotating or static), must be capable of operating continuously at a power factor above 0.9 lagging. Non-conforming loads must be corrected to within the acceptable range to be considered for interconnection.

4.4. Power Quality.

4.4.1. Harmonics

The Load Customer will be required to mitigate harmonic currents resulting from non-compliance with IEEE Std 519-1992 "Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems".

4.4.2. Resonance

The Load Customer must design the load facility to avoid introducing undue resonance into the IES. Of particular concern are self-excitation of induction motors, transformer ferroresonance, and the resonant effects of capacitor additions. The Load Customer must be able to demonstrate that the facility is compliant.

4.4.3. Voltage Flicker

The Load Customer shall be required to carry out corrective action if the load facility imposes upon the power system voltage depressions in excess of the maximum permissible voltage flicker limits as defined in IEEE Std 519-1992 “Recommended Practices and Requirements for Harmonic Control in Electrical Power Systems”.

4.4.4. Voltage Unbalance

The load facility shall not increase the phase-to-phase voltage unbalance of the system, as measured with no load and with balanced three-phase loading, by more than 1% at the point of interconnection. Voltage unbalance will be calculated using:

Unbalance (%)= 100 x (deviation from average) / (average)

as derived from NEMA MG1-14.33.

4.5. Transformer Connection.

The interface transformer connection shall be designed to provide:

- a favorable circuit to block the transmission of harmonic currents; and.
- isolation of transmission and load side ground fault current contributions.

For individual loads directly connected to the Transmission System, the preferred transformer configuration is a delta connection on the transmission supply side of the transformer and a wye connection on the load side of the transformer.

Load Customers should interconnect to the distribution systems with either wye/wye or delta/wye configured transformers, which ever is more appropriate for the particular distribution system.

4.6. Protection and Control Interface.

4.6.1. Line Protections.

The Load Customer must provide line protections if transformers connected to separate supply circuits are:

- operated in parallel on the low voltage side, or
- if a synchronous fault current infeed, such a parallel connected generator or large synchronous motor exists at the low voltage bus.

4.6.2. Bus Protections.

If a single bus differential relay scheme may be applied without jeopardizing system security, then time-delayed remote backup protection will be provided by the remote end overreaching line protections facing the protected bus.

4.7. Underfrequency Load Shedding.

Underfrequency load shedding is used to ensure that a synchronously interconnected electric system continues to operate within an acceptable frequency range whenever generation suddenly becomes insufficient to meet the connected load of the system. When underfrequency load shed protections detect a decay of frequency following a significant resource loss, they shed sufficient load in order to maintain acceptable system frequency. The load shed sequence will be prioritized so that less critical loads are shed first, to ensure uninterrupted service to essential loads.

All Load Customers are required to participate in the IES underfrequency load shedding program, per TAOP 1700. The Load Customer shall ensure that sufficient load is equipped with under-frequency load shedding relays armed in each frequency band to meet the program specifications and that the under-frequency protection scheme is appropriately installed, tested and commissioned.

4.8. Undervoltage Load Shedding.

During severe but infrequent situations, such as a multiple simultaneous circuit outage, load shedding may be necessary to prevent cascading voltage collapse. The Transmission Administrator will notify the load customer of any undervoltage load shed requirements as they become known. As with underfrequency load shedding, the undervoltage load shed sequence will be prioritized so that less critical loads are shed first to ensure uninterrupted service to essential loads.

4.9. Billing Metering.

The cost of billing metering is the responsibility of the Load Customer. The Load Customer can choose to supply the necessary metering in accordance with the requirements of the Transmission Administrator or arrange for an acceptable third party to supply metering. Alternatively, the Load Customer can request the Transmission Administrator to arrange for the necessary metering installation. Metering Equipment includes, but is not limited to, the instrument transformers (voltage transformers, current transformers), secondary wiring, test switches, meters and communication interface. Unless otherwise agreed to by the Transmission Administrator, the instrument transformers should be dedicated for metering purposes only.

4.10. Supervisory Control and Indication.

A load Customer seeking interconnection to the IES for loads larger than 10 MVA must be equipped for supervisory indication. This is required to ensure that the proper level of system visibility is maintained for overall network security. The Load Customer shall provide, as a minimum, a Remote Terminal Unit (“RTU”), capable of communicating the following supervisory control and data acquisition (“SCADA”) information with the SCC:

- Interconnection breaker(s) status (if not installed, then the status of the load interrupter(s) or isolation device(s) shall be provided instead);
- Load MW and MVAr measured at the high voltage side of the transformer(s) stepping voltage down from transmission voltage to primary side utilization voltage; and
- Voltage of the high voltage bus at the step down transformer(s).

Additional SCADA data that is desirable, although not mandatory:

- MW and MVAr line flow on any transmission line coming into the plant substation; and
- The tap position of any on load tap changing (LTC) transformer in service connected to the transmission voltage bus(ses).

Loads offering system support services may require additional SCADA capability as outlined in Section 5.

5. Technical Issues Requiring Commercial Arrangements.

Load Customers capable of, and interested in, providing or receiving services beyond the minimum requirements in the previous section should contact the Transmission Administrator's Customer Service Manager:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

6. Responsibility of the Transmission Administrator.

The Transmission Administrator is responsible for overall planning of the IES and is accountable to ensure that all additions to transmission rate base are prudent. The Transmission Administrator maintains a technical database for all IES facilities which is publicly available on the Transmission Administrator's website at www.eal.ab.ca. The Transmission Administrator will provide to the proposed Load Customer any other specific information as required and appropriate to enable interconnection of the proposed facilities.

6.1. Contact Organizations

The Transmission Administrator shall provide the name and telephone number of contact persons at the Transmission Administrator's office, the Alberta Energy and Utilities Board (AEUB), the Power Pool of Alberta and the System Controller.

6.2. Technical Information

The Transmission Administrator conducts the planning studies required to assess the security of the IES and to plan for future additions of equipment and services in light of IES security requirements. The Transmission Administrator may choose to make the results of studies available to the Load Customer to help establish interconnection parameters, such as voltage level selection, voltage regulation requirements, short circuit capacity impacts, stabilizer parameter determination, participation in special RAS's, and so on.

As they occur, the Transmission Administrator shall provide the Load Customer with information relative to any changes in system operating standards and procedures that may affect the operation of the Load Customer's facilities.

6.3. *Acceptance of the Interconnection*

The Transmission Administrator shall review and may, at its sole discretion, choose to accept the interconnection of facilities meeting the Transmission Administrator's requirements. The Transmission Administrator shall witness any interconnection commissioning test the Transmission Administrator deems necessary and shall keep copies of all interconnection commissioning test results.

6.4. *Agreements*

The Transmission Administrator shall implement the relevant interconnection tariffs, and shall support the Load Customer in obtaining any operating agreements required to permit interconnection.

7. Responsibility of the Load Customer

To enable exchange of power with the Power Pool of Alberta, the Load Customer must become a Power Pool Participant and comply with any Power Pool requirements. The interconnection of new load facilities may require modification of transmission facilities owned by one or more Transmission Facility Owners. Commercial terms to cover the costs of such modifications will be determined by Transmission Administrator in accordance with the Transmission Administrator's Tariff. For commercial details, contact the Transmission Administrator's Customer Service Manager:

- E-mail: customer-service@eal.ab.ca
- phone: (403) 232-0944

7.1. *Technical Information.*

The Load Customer shall provide all applicable basic load information listed in **Appendix A** and analytical modeling information listed in **Appendix B** to the Transmission Administrator.

Appendix A: Basic Load Data.

The Load Customer shall submit to the Transmission Administrator detailed information as required to design, construct, operate and maintain the Transmission Facilities Owner's portion of the interconnection.
Such information shall include:

I. Contact names, mailing addresses, phone and fax numbers, e-mail addresses for
   A. commercial terms;
   B. engineering design; and
   C. operating terms.

II. Siting Information
   A. a detailed map showing the proposed load location;
   B. a site plan showing the arrangement of the major equipment; and
   C. diagram showing the voltage and current rating of each major component.

III. Interconnection Protection
   A. complete and accurate protection diagrams;
   B. a description of the proposed protection schemes; and
   C. maintenance plans for the interconnection protective devices and interconnection interrupting devices.

IV. Power Factor Regulator
   A. limits of range of reactive power (VAr) lagging and leading; and
   B. accuracy tolerance of setting.

V. Motors
   A. Type;
   B. make and model;
   C. nominal MVA rating; and
   D. nominal voltage rating.

VI. Voltage Regulator (synchronous motors and static equipment)
   A. voltage regulator setting range;
   B. voltage regulator setting tolerance;
   C. Compensator;
   D. type of input(s);
   E. compensating resistance(s); and
   F. compensating reactance(s).

VII. Transformers
   A. MVA base rating.;
   B. fan rating, cooling type;
   C. high voltage - nominal voltage, connection;
   D. low voltage - nominal voltage, connection;
   E. tapchanger - on-load or off-load, tap chart; and
   F. ratio and accuracy class of instrument transformers. If multi-ratio, state the available ratios and the proposed ratio.

Appendix B: Analytical Modeling Information.

I. Large Motors.

In the event that the load includes large (500 kVA or above) induction or synchronous motors connected to the grid, the Load Customer shall submit to the Transmission Administrator detailed information as required to model the transient, dynamic and steady-state behavior of the rotating equipment consistent with WSCC modeling criteria. The Load Customer is responsible for ensuring that the data submitted provides an adequate mathematical representation of his facility's electric behavior. Data is adequate if it allows the Transmission Administrator to determine accurately:

- the impact of the facility on other customers on IES; and
- the dynamic stability, in aggregate, of the IES as an interconnected system within the WSCC.

Such additional information shall include:

A. For Synchronous motors only.

1. Speed (RPM);
2. Inertia constant (H);
3. Damping Factor (D);
4. Direct axis synchronous reactance (x_d);
5. Direct axis transient reactance (x'_d);
6. Direct axis subtransient reactance (x''_d);
7. Direct axis transient time constant (T'_{do});
8. Direct axis subtransient time constant (T''_{do});
9. Quadrature axis synchronous reactance (x_q);
10. Quadrature axis transient reactance (x'_q);
11. Quadrature axis subtransient reactance (x''_q);
12. Quadrature axis transient time constant (T'_{qo});
13. Quadrature axis subtransient time constant (T''_{qo});
14. Stator Resistance (R);
15. Stator leakage reactance (X_l);
16. Saturation factor at 1.0 per-unit flux ($S_{1.0}$)*;
17. Saturation factor at 1.2 per-unit flux ($S_{1.2}$)*;
18. Negative sequence resistance (R_2);
19. Negative sequence reactance (X_2);
20. Zero sequence resistance (R_0);
21. Zero sequence reactance (X_0);
22. Excitation system type (AC or DC; rotary, "brushless" or "static"; et cetera)**;
23. Excitation system Filter time constant (T_r)**;
24. Excitation system Lead time constant (T_c)**;
25. Excitation system Lag time constant, (T_b) **;
26. Excitation system Controller Gain (K_a) **;
27. Excitation system Controller lag Time constant (Ta)**;
28. Excitation system Maximum Controller output (V_{rmax})**;
29. Excitation system Minimum Controller output (V_{rmin})**;
30. Excitation system regulation factor (K_c)**;
31. Excitation system Rate feedback gain (K_f)**; and
32. Excitation system Rate feedback time constant (T_f)**.

* *Or, submit saturation curves.*

** *Or, submit a Laplace-domain control block diagram showing all control blocks with all time constants greater than 0.02s, completely specifying the transfer function from the compensator output voltage (or generator terminal voltage, if there is no compensator) and field current, to the generator field voltage.*

B. For Induction motors only.

1. Speed (RPM);
2. Inertia constant (H);
3. Steady-state reactance (x_d);
4. Subtransient reactance (x'_d);
5. Transient reactance (x'');
6. Subtransient time constant (T');
7. Transient time constant (T'');
8. Stator Resistance (R);
9. Stator leakage reactance (X_l);
10. Saturation factor at 1.0 per-unit flux ($S_{1.0}$)*;
11. Saturation factor at 1.2 per-unit flux ($S_{1.2}$)*;
12. Negative sequence resistance (R_2);
13. Negative sequence reactance (X_2);
14. Zero sequence resistance (R_0); and
15. Zero sequence reactance (X_0).

* *Or, attach saturation curves.*

II. D.C. drive controller.

A. Submit a Laplace-domain control block diagram showing all control blocks with all time constants greater than 0.02s, completely specifying the transfer function from the inputs, to the power outputs, stabilizing loops, voltage control loops.

B. Submit an A.C. / D.C. single line diagram of the power network showing the filters, compensators, rectifiers and indicating the fixed and controlled equipment.

III. Compensator.

A. Type of input(s);
B. Compensating Resistance(s); and
C. Compensating Reactance(s).

IV. Transformers.

A. Positive Sequence Impedance;
B. Negative Sequence Impedance.; and
C. Zero Sequence Impedance.

.

Appendix C: Revision History

Revision Number	Revision Date	Comment
1.0	1999/12/02	Part 2 of the interconnection document revised to reflect changes in regulations. The Alberta Communications and Utilities Safety Regulation (ECUSR) was rescinded on 1999/11/01, and superceded by The Alberta Electrical and Communication Utility Code (AECUC).