Alberta Interconnected Electric System Protection Standard

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Signature Page

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1.0 STAKEHOLDER REVIEW COMMITTEE

The Stakeholder Review Committee, listed separately, acknowledges that the Protection Standard is the first overarching protection standard for the AIES. The Stakeholder Review Committee also acknowledges the impact other AESO Engineering Standards may have on the Protection Standard including but not limited to NERC/WECC Planning Standards and AESO Interconnection Standards. The member of the Stakeholder Review Committee are listed following.

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2.0 SCOPE AND APPLICABILITY

This Standard defines the minimum level of protection to be applied to equipment connected to the Alberta Interconnected Electric System (AIES). This Standard is applicable to the AIES grid system sometimes referred to as the Bulk Electric System (BES) and covers the protection applied to generators, transmission lines, and interconnecting stations including the first distribution level voltage at the connected station. For example, a station with a 138/25 kV transformer, protection applied to the 25 kV bus and feeders must conform to this Standard with regard to protecting the AIES from disturbances originating on the 25 kV bus and feeders. This means faults or other disturbances on the 25 kV bus must not cascade trip the 138 kV voltage equipment. Distribution lines connected to stations are not covered, however, protection applied to those lines must ensure that faults outside of the stations do not cascade trip back onto the AIES.

The Standard is applicable on a ***go forward basis***, that is the Standard shall not be used as justification to retrofit or change existing protection schemes applied to the AIES that are not compliant with this Standard. The AESO reserves the right, on a case-by-case basis, to endorse retrofitting protection not compliant with this Standard for those stations the AESO deems critical to the AIES.

The following voltage levels are covered by this Standard:

2.1.1 500 kV

The AESO in conjunction with the Equipment Owner will define all protection requirements for 500 kV equipment and facilities. Deviation from the AESO's requirements will require written permission of the AESO.

2.1.2 240 kV

Protection applied to 240 kV equipment and facilities will be defined by this Standard. Deviation from this Standard will require the Equipment Owner to file an Applications Engineering Summary with the AESO.

2.1.3 138/144 kV and Lower Voltages

Protection applied to 138/144 kV and lower voltage equipment shall use this Standard as a guide and follow existing Equipment Owner protection application philosophies. Lower voltage equipment connected to 240 kV equipment through step up or step down transformers shall conform to the 240 kV protection requirements.

2.2 REQUIREMENTS FOR REVIEW

This Protection Standard expires and must be reviewed within five (5) years of the effective date shown on the cover page and given below. The

Protection Standard may, at the request of the AESO, stay in force during the review period, but shall automatically cease to have force twelve (12) months after the five-year expiry date.

The in-service or effective date for the Standard is *December* 1, 2004.

3.0 SYSTEM REQUIREMENTS

3.1 GENERAL

The emphasis for protection application is to protect the AIES from the effects of disturbances and faults on protected equipment, minimize the equipment removed from service during these conditions and at the same time allow the interconnected electric system to continue serving native Alberta load.

Public safety and protection of workers in stations is also part of the protection application. Personnel safety is covered by safe operating practices designed and instituted by the Equipment Owner and by the design of equipment, equipment layout and station grounding. While protection application is not specifically designed for personnel safety, it forms part of the safety program.

The Protection Standard recognizes that the development of an overarching standard for Alberta will be an evolutionary process which takes into account the differences in protection application practices employed by the various Equipment Owners, the continuing development of numerical protection and measurement systems and the continuing development of the AIES.

This Standard shall not be used to justify retrofitting of protection to equipment that does not comply with this Standard. The equipment owner shall notify the AESO that their protection is not in compliance with the Protection Standard and submit a proposal to the AESO to bring the protection equipment into compliance with this Standard.

The AESO will not approve any protection application but may at its sole discretion support any protection application that is not in compliance with this Standard provided the Equipment Owner demonstrates that the protection is required to either protect their equipment or protect the AIES from the effects of not removing their equipment from the AIES.

3.2 SECURITY AND ACCESS

Implementation of Section 3.2 is deferred until a later date.

Numerical protection systems allow remote access to either or both change the relay settings or download data captured by the protection system's fault or data recorder.

Remote access to the protection system shall incorporate a two level password system. The first password shall gain access to the protection system. The second password shall allow the relay settings to be remotely changed. If applicable, a third password shall allow access to captured data. Passwords shall be changed a minimum of four (4) times annually.

The use of the manufacturer’s default passwords is expressly forbidden.

3.3 PRINCIPLES

Principles are divided into required and recommended. Required principles are a requirement of the AESO and recommended principles are preferred application.

The application of protection to the AIES takes into consideration many factors. Consequently, protection settings for the most part can not be prescribed by the AESO. Settings for protection equipment, except where specifically noted, are for illustration purposes only.

3.3.1 Required

- At the request of the AESO, the Equipment Owner shall prepare an Applications Engineering Summary and submit the report to the AESO.

- Where the protection application has deviated from this Standard, the Equipment Owner will file an Applications Engineering Summary with the AESO.

- Protection application, including relay choices and settings, are the sole responsibility of the Equipment Owner and not the AESO. The AESO accepts no responsibility for improper application of protection devices.

- In cases where the protection application for the equipment conflicts with the AIES system requirements, precedence shall be given to protecting the equipment. Sufficient studies shall be completed by the Equipment Owner to: a) document that a conflict exists and b) provide sufficient evidence that cascade tripping or mis-coordination will not occur for the proposed protection application.

- The AESO will define the protection requirements for applications related to system protection. It is the responsibility of the Equipment Owner to ensure that the protection requirements defined by the AESO to protect the AIES are reliable and secure, and are adequate for their operation.

- For AIES grid stations where equipment is paralleled, e.g. transformers, or stations with ring or breaker and half/third bus configurations, the AESO will define the requirements for auto isolation of faulted equipment. It shall be possible to reclose automatically the unfaulted equipment and/or restore the ring bus after auto isolation of the faulted equipment.

3.3.2 Recommended

- The AESO may recommend to the Equipment Owner that the protection application be modified; however, the Equipment Owner is under no obligation to accept the AESO’s recommendation.

- Protection applied to the AIES is designed to protect equipment and facilities connected to the AIES.

3.4 REQUIREMENTS FOR WECC/NERC COMPLIANCE

The protection applied to the AIES shall comply with the WECC/NERC Planning Standards. Where the requirements for protection application in this Standard exceed the WECC/NERC requirements, this Standard shall prevail.

The AESO has issued draft Reliability Criteria dated June 18, 2004. Where applicable, the application of protection to the AIES shall comply with the Reliability Criteria. The AESO Reliability Criteria follows with some clarification the WECC/NERC Planning and Operating Standards.

For application of protection to the AIES and compliance with WECC/NERC Standards, the following statement shall serve as a guideline.

All transmission equipment rated 240 kV and above including generation and/or load connected via step up or step down transformers is defined as transmission that is to be WECC/NERC compliant. At the AESO's discretion, this may also include lower voltage equipment and facilities connected to 240 kV equipment.

3.5 RELIABLE (DEPENDABLE AND SECURE)

All protection applied to the AIES shall be reliable, that is both dependable and secure. Dependable means the protection shall operate correctly for all faults within the zone of protection and secure means the protection shall remain stable and not operate for faults outside the zone of protection.

3.6 FAULT TYPES

Protection applied to the AIES is designed to detect successfully all faults on the protected equipment, initiate isolation of the faulted equipment from the AIES and, where applicable, initiate auto-isolation of faulted equipment and/or initiate high-speed auto-reclose.

System planning criteria is based on clearing a three phase bolted fault on the equipment terminals in a time frame, usually given in cycles at 60 Hz, that will ensure system stability. The criterion assumes no dc offset.

Protection applied to the AIES must be capable of successfully detecting and initiating isolation and, where applicable, initiating auto-isolation and/or reclose of the following fault types:

- Single line to ground faults with 20Ω (tower footing plus arc) impedance
- Phase to phase faults
- Phase to phase to ground with 20Ω (tower footing plus arc) impedance

- Three phase to ground

The AIES shall remain stable following the isolation of the faulted equipment by the protection system. All protection applied to the AIES shall be designed such that cascade tripping does not occur. Specific applicability of these criteria is discussed in more detail in the following section dealing with the protection applied to individual pieces of equipment.

3.7 TRIPPING SPEEDS (MAIN AND BACKUP)

NERC/WECC Planning Standards do not address required tripping speeds. Rather the Standard requires the electric system to remain stable without cascade tripping (WECC/NERC Category B and C).

Maximum primary protection tripping times for AIES voltage levels shall be:

- **500 kV – 0.067 seconds (4 cycles)**
- **240 kV – 0.083 seconds (5 cycles)**
- **138/144 kV – 0.1 seconds (6 cycles)**

Tripping times are based on clearing a three phase symmetrical fault on the affected bus with no dc offset and are for the local bus only. High-speed clearing of the fault by the remote bus may occur approximately one to two cycles later.

Speed of operation includes relay detection time, auxiliary relay time, communication time and maximum breaker interruption time. High-speed tripping means that no intentional time delay is applied. Slow-speed tripping means that a time delay is incorporated into the protection system. This time delay can be either in the fault detection apparatus or in the tripping circuit.

3.8 LINE LOADING

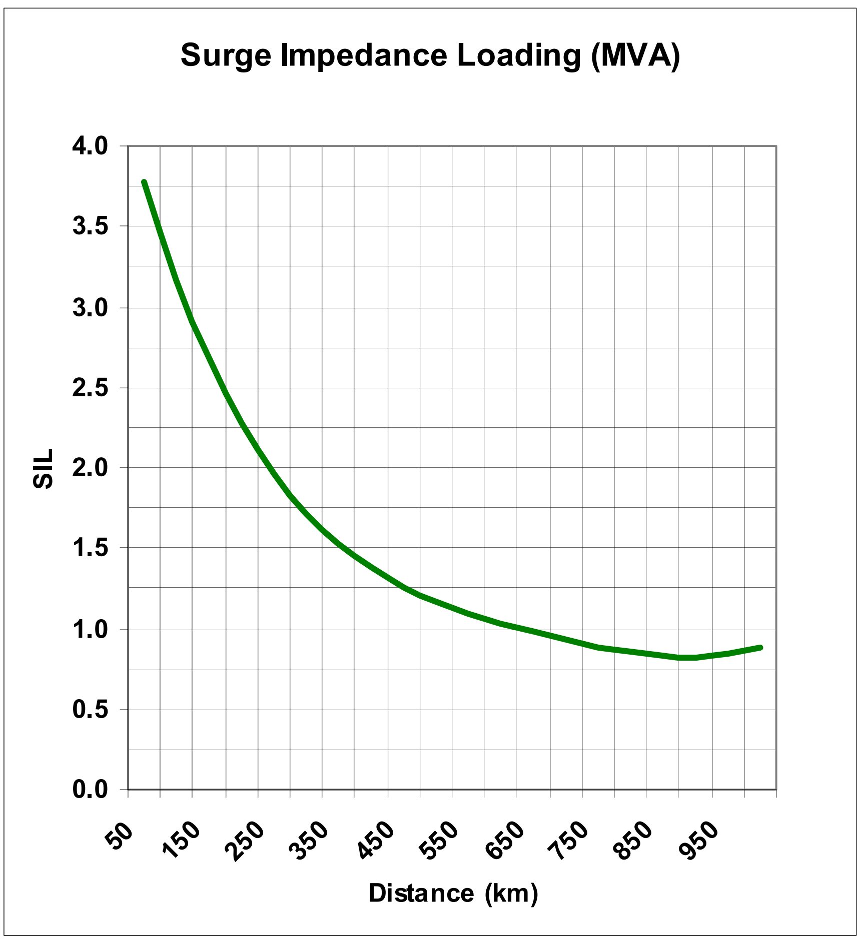
Transmission line loading shall be based on the St. Clair Curve as shown below. Line loading shall include normal operating conditions (all equipment in service) and contingency conditions (equipment out of service for maintenance or forced out due to a fault).

Line loading is given in MVA at 0.9 pf. The equivalent sending and receiving end sources are based on a breaker fault current rating of 40 kA. For determining load encroachment, the load angle will be assumed 30^{o} lead and lag.

In general, all lines less than or equal to 80 km are designed for three times Surge Impedance Loading (SIL) in MW. The St. Clair Curve assumes line loading is independent of conductor thermal ratings. Lines greater than 80 km shall follow the line loading shown in the St. Clair Curve.

Line loading given by the St. Clair Curve assumes point-to-point transmission in the electric system. The loading of the line in the AIES is impacted by the surrounding system including but not limited to transformers, generators and other transmission lines of equal, higher or lower voltage. Consequently, the St. Clair Curve gives an optimistic value of loadability. In actual practice, the line loading will be less. However, the protection application engineer should be aware of the line loading as defined by the St. Clair Curve and consider that loading in designing the line protection, especially as it affects higher zone impedance relay load encroachment.

Below approximately 350 km the voltage drop determines line loading across the transmission line from terminal to terminal. Above approximately 350 km line loading is determined by the steady state stability criteria. Values for both are given in the following subsections of this Standard.



Characteristics of AIES Transmission Lines

Voltage (kV)	SI (Ω)	R (Ω/km)	X (Ω/km)	Charging (kVAr/km)	SIL (MW)	X/R
69/72	370	0.4	0.5	15	13/14	1.2
138/144	370	0.2	0.5	70	50/55	2.5
240 single	340	0.07	0.45	225	170	6
240 bundle	300	0.07	0.4	290	195	6
500	250	0.018	0.345	1340	990	20

Protection application shall include recognition of both angular and voltage criteria. Protection applied to the AIES shall be capable of detecting violations of both conditions and initiating corrective actions to mitigate the effects of exceeding these criteria.

3.8.1 Voltage Criteria

Line voltage drop is defined as the absolute difference between the voltage measured at the sending end and the voltage measured at the receiving end divided by the sending end voltage all at the same voltage level. Voltage drop across any transmission line during steady state operating conditions is typically limited to 0.05pu.

Voltage drop across any transmission line during a single contingency event is limited to 0.1 pu. For example, on a parallel transmission line, the voltage drop across the two lines in service is limited to 0.05pu at the full load carrying capability defined by the St. Clair Curve. For one line out of service, the voltage drop across the remaining line is limited to 0.1 pu.

3.8.2 Stability (angle and voltage)

Angular stability criteria are defined by the maximum electrical angle allowed across a portion of the AIES. The measured angle includes the angles across the equivalent Thévenin impedances behind the protected equipment at both the sending and receiving ends. This represents an angle of between 40^{o} to 45^{o} across that portion of the system. Typical design loading (angle) for AIES transmission lines shall be 20^{o} for non-contingency conditions. During contingency conditions, the angle may increase to 30^{o}.

Steady State Stability Limit is defined as the difference between maximum line loading and line loading divided by the maximum line loading and expressed as a percent. Typical values are between 30% to 35%.

Voltage stability criteria are defined in terms of the requirement to have sufficient VAr margin on the transmission system to allow the transmission system to continue to supply some of or the entire connected load. Two measures are used; load margin and reactive margin. Undervoltage load shedding is applied to mitigate the effects of deficient VAr supply.

3.9 SYSTEM CONDITIONS

Protection applied for system conditions assumes the equipment is not in a fault condition, but there exist on the AIES or outside of the AIES conditions that may cause the AIES to go unstable or operate outside defined limits if the condition persists for more than a predefined time. System protection requirements include under/over frequency and under/overvoltage detection systems. Remedial Action Schemes are also included. For these cases protection application and protection settings will be established by the AESO in conjunction with the Equipment Owner. This system condition may have the potential to damage equipment connected to the AIES and the protection application engineer is responsible for: a) ensuring that their equipment does not contribute to the potential instability on the AIES and b) protecting their equipment from the effects of the abnormal system condition.

3.9.1 System Transients

The protection system shall be designed to remain stable during system transients and out of zone faults, but shall be capable of detecting faults and tripping during the dc time constants relevant to the system X/R ratios at the protection equipment location and shall operate correctly regardless of prior system conditions. System X/R ratios vary from 50 to 2.

3.9.2 Mutual Impedances

For transmission line protection, the application shall take into account the zero sequence mutual coupling during fault conditions. The under/over reach of the distance element shall be either mitigated or the Zone 1 reach adjusted accordingly.

Protection application must take into account the possibility of zero sequence voltage reversal during line to ground faults due to the mutual coupling effect from adjacent lines not connected to the same source.

3.10 PROTECTION ZONES

Three protection zones are defined: detection, clearing and isolation.

Detection zones are defined by the location of the current transformers or voltage transformers or a combination of both.

Clearing zones are defined by breakers. The breakers may be at the same voltage or different voltages. The clearing zone may be defined by the remote end breaker.

Isolation zones are defined by breakers or disconnects or a combination of both.

Protection zones shall minimize the interference with unfaulted equipment. Automatic sectionalizing of paralleled equipment shall be employed for parallel connected equipment. Auto restoration of unfaulted equipment may be required after auto sectionalizing of paralleled equipment except where specifically noted.

3.11 LOCKOUT VERSUS NON-LOCKOUT

In general, equipment with non-restoring insulation, e.g. transformers, requires lockout tripping. Lockout tripping is also initiated from breaker fail protection. Equipment with restoring insulation, e.g. transmission lines, requires non-lockout tripping. Lockout tripping requires the Equipment Owner to go physically to the station and determine if the equipment can be re-energized. Non-lockout tripping allows the operator to re-energize the equipment from a remote location. Non-lockout tripping applies to the first trip only. Dependent on equipment and operating constraints, subsequent trips may be lockout.

Breaker lockout may be remotely reset for paralleled equipment if an auto-isolation scheme is installed.

3.12 PROTECTION APPLICATION TYPES

Three types of protection are applied to the AIES.

- Fault relaying detection – a fault in equipment characterized by insulation failure and requires high-speed tripping. High-speed lockout or non-lockout protection may be applied.

- Abnormal operating condition detection – a condition where the equipment is operating outside of its operating characteristics and is not indicative of an insulation failure. However, loss of equipment life and/or insulation failure may occur if the condition is not detected within a definite time. Slow-speed non-lockout protection is applied.

- Abnormal system condition detection – an over/under frequency or an over/under voltage operating condition. Remedial Action Schemes are also included in abnormal operating conditions. Non-lockout protection is applied.

3.13 HIGH-SPEED FAULT THROWING SWITCHES

For transformer-ended lines at 240 kV, the use of high-speed single phase to ground fault-throwing switches is not permitted under any circumstances. The use of these switches at 138 kV and lower voltages is discouraged.

3.14 CONTINGENCIES

Protection systems are designed to successfully detect and isolate double contingency events. A double contingency event is defined as two failures of two different types. The first contingency is the fault occurrence. The second contingency is equipment failure and includes protection equipment out of service for routine maintenance or testing.

3.15 DEFINITION AND DESIGN OF THE PROTECTION SYSTEM

The protection system is defined as the measurement devices, fault detection systems, auxiliary equipment, communication equipment, tripping relays and the associated interconnections necessary for the successful detection, interruption and isolation of the protected equipment and, as applicable, high-speed reclosing.

Dual protection systems, except as specifically noted, shall be applied to all AIES connected equipment. Dual protection systems shall be equal in function and speed.

The protection system shall be designed such that one complete protection system can be taken out of service for routine maintenance or testing without interfering with the other protection system.

A minimum of two independent protection systems shall be applied to equipment and each system shall operate independently of each other. Dual trip coils shall be standard equipment on all 240 kV and higher rated equipment. Communication circuits may use the same path; however, separate signals should be employed.

Dedicated potential transformer windings, current transformer windings, communication systems, interconnecting cables, power supplies and trip outputs shall be employed for each protection system.

3.16 INSTRUMENT TRANSFORMERS

Protection class voltage and current transformers shall be employed on the AIES. Separate current cores and separately fused voltage supplies shall be employed for each protection system. It shall be possible to isolate any protection system from service to do routine testing or maintenance without affecting in any manner whatsoever the remaining protection system for the equipment.

3.16.1 Voltage Transformers

Either wire wound, capacitive or optical voltage transformers shall be used on the AIES. Voltage transformers shall be correctly sized for system voltage and relay load conditions to avoid excessive voltage drop and phase angle error.

Fuse failure protection is required at 500 kV and on all generators rated 100 MVA and higher.

In the rare case where the system is designed or can operate ungrounded for long periods of time, the voltage transformers shall be rated for line to line voltage.

3.16.2 Current Transformers

Current transformers shall be either magnetic or optical. Current transformers shall be designed such that the transformer shall not limit the equipment loading.

Current transformers shall be designed with a continuous current rating of 125% of the maximum expected circuit loading. In order to maintain the measuring accuracy of the line distance protection, the current transformer core output shall be high enough to ensure that the core is not saturated for a fault at the end of distance protection Zone 1 with a maximum dc offset and the system time constant, X/R ratio for this fault position. The empirical formula which can be used when no detailed calculation formula is given by the relay supplier is:

$$E_{sat} > I_F*(X/R+1)*(R_{ct}+R_l)$$

Where:

- E_{sat} is the CT minimum voltage output, e.g. 2.5L400 has an output of higher than 400V. In reality, 400+100* R_{ct}.
- I_F is the maximum fault current for a fault at Zone 1 reach in secondary amperes.
- R_{ct} is the secondary resistance of the CT.
- R_l is the total load resistance in the current loop. One-way cable for multi-phase faults and two way for ground faults.
- X/R is the total X/R for the fault at the fault position.

3.17 SYSTEM GROUNDING

The AIES is designed as an effectively grounded system, i.e. the X_o/X_1 ratio is less than or equal to three. The AIES shall remain effectively grounded system with equipment out service.

In rare cases where the AIES is not effectively grounded or where operation of the AIES causes the system X_o/X_1 ratio to exceed three, consideration shall be given to the application of equipment rated line to line for the system voltage on that part of the AIES.

3.18 PROTECTIVE DEVICE POWER SUPPLIES

Independent power supplies are required for each protection system. For stations with a primary voltage of 240 kV and above, two battery banks may be required. Requirements for a second battery bank shall be decided by the AESO in consultation with the Equipment Owner. For lower voltage stations only one battery bank is required.

Each protection system shall be supplied from separately fused dc circuits. It shall be possible to isolate a protection system from its dc circuit without affecting other protection systems in the station. Isolation of the dc circuits shall be by double pole breakers.

3.19 EXPECTED LIFETIME

Protection systems shall be designed for an expected lifetime of more than 20 years.

4.0 TRANSMISSION LINES

4.1 GRID PROTECTION

This section covers the application of protection to the AIES transmission system. This includes all 500 kV, 240 kV and 138 kV transmission lines on the AIES. Transmission lines rated at 500 kV shall follow the requirements of this Standard. Transmission lines rated at 240 kV shall use this Standard as the recommended practice. Transmission lines rated at 144/138 kV and lower shall use this Standard as a guide and may follow accepted utility practice.

Two independent high-speed protection systems shall be applied to all 138 kV and higher voltage transmission lines. At 500 kV, each protection system shall be completely independent of the other and shall be either from different manufacturers or use different protection principles. The reasons for this are to avoid type faults, ensure operation for evolving and simultaneous faults and avoid blind spots in the protection schemes. Each protection system shall be fed from its own secondary voltage and current source. Independent communication channels shall be employed for each protection system. It shall be possible to isolate one protection system for maintenance and testing without interfering with the operation of the transmission line and the other protection system in any way whatsoever. This isolation includes the requirements for end-to-end testing of the protection system.

4.2 FAULT CONFIGURATION, ZONES OF PROTECTION AND SETTINGS

Transmission protection shall be zoned from breaker to breaker. Sub zoning is required for transformer-ended lines to identify transformer faults.

Fault types are defined in Section 3.6 of this Standard.

Both line to ground and phase to phase faults may evolve to double line to ground faults as a result of tower backflash prior to clearing. The protection system must operate reliably for this condition.

An evolving fault is any fault configuration outside the original line to ground or phase to phase fault and includes cross-country faults. The protection system is not designed to interrupt cross-country faults and the AIES may experience instability during this fault configuration.

Three phase faults to ground are considered rare. However, three phase faults as a result of maintenance grounds left connected to the system after maintenance do occur. Protection shall be applied to detect these faults.

Transmission line impedance relays shall typically have Zone 1 set at 85% of line length. Zone 2 shall be set at 125% of line length with a minimum time delay of 0.25 seconds (15 cycles). The Zone 2 timer shall coordinate with the remote station breaker fail protection such the remote breaker fail protection shall attempt to clear the local bus first. A longer time delay can be used provided system studies determine its applicability.

Impedance characteristics shall be circular or quadrilateral and capable of adapting to system conditions. That is, the distance relay shall incorporate a polarizing voltage from either the leading unfaulted phase to ground or the unfaulted phase to phase voltage or memory voltage. Where applicable, the circular characteristic shall include a load encroachment characteristic.

4.3 RADIAL PROTECTION

Protection applied to radial transmission lines shall conform to the voltage class of the line. Radial transmission lines that have distribution connected generation (greater than 5 MW in aggregate) are considered grid transmission lines and applicable grid transmission line protection is to be applied.

4.4 ZERO SEQUENCE VOLTAGE AND CURRENT POLARIZING

The use of directional overcurrent relays employing zero sequence voltage or current polarizing must take into account the effects of mutual impedances from parallel lines on the polarizing elements. Protection settings shall mitigate the effect of voltage reversal that can lead to misoperation of the directional element.

4.5 SINGLE AND THREE POLE TRIPPING

All 240 kV and above transmission lines shall be equipped for both single and three pole tripping. During the single pole open condition, the healthy phases of impedance relays shall not operate and the protection scheme shall be capable of detecting evolving faults and power swing conditions. 67N and 51N protection schemes may require blocking during the single pole open condition.

All 138 kV and lower transmission lines shall be equipped for three pole trip.

4.6 AUTO-RECLOSING

All 240 kV and higher voltage transmission lines shall be equipped for and be capable of single pole auto-reclosing. The minimum line dead time shall be set at 0.75 seconds (45 cycles) for single pole reclose. Use of a longer dead time is permitted, provided system studies indicate its applicability. Use of a shorter dead time is not permitted. Only one auto-reclose attempt shall be made to reclose the line. Three pole tripping is required if the single pole auto-reclose is unsuccessful. Subsequent reclose attempts shall be by operator control. For multi-phase faults at 240 kV, the lines shall be equipped for three pole trip and reclose.

All 138 kV lines shall be equipped for three pole trip and reclose. The line dead time shall be between 2 to 3 seconds. Use of a longer dead time is permitted, provided system studies indicate its applicability. Use of a shorter dead time is not permitted. Two attempted auto-recloses at 138 kV are permitted. The second reclose attempt shall be delayed by a minimum of 15 seconds. Subsequent reclosures shall be by operator control.

Line check relaying may be applied at the discretion of the Equipment Owner. If applied, line check relaying shall be applied to check that the arc has been successfully extinguished. Line check relaying shall be applied at both ends of the transmission line. As a general rule, the end with the higher three-phase short circuit shall be closed first. Transmission lines that connect generating stations to the AIES shall be reclosed from the remote end first. No other time delay in reclosing the remote end shall be applied. Dedicated short lines that connect generating stations to AIES stations shall not have reclosing applied.

Line dead time is measured from the breaker open contacts until the instant the breakers contacts start to close. The breaker open contacts shall supervise the reclose timer. The use of interposing relay contacts to indicate the open breaker position is discouraged.

Zone 2 impedance protection is to be enabled during auto-reclosing of transmission lines with the transmission line capable of tripping instantaneously via Zone 2 if the fault re-establishes.

Transmission auto-reclose shall be designed to have a success rate greater than 90% measured on a calendar basis. The success rate shall be measured as the ratio of successful reclosures divided by the number of attempted reclosures (both successful and unsuccessful) multiplied by 100. This recognizes that the relays, breakers and communication must all work together. Separate records shall be kept for each voltage class and for single and three-pole reclosure.

4.7 SYNCHRONIZING CHECK RELAYING

Two types of synchronizing check relaying are applied to the AIES. The first type checks that the voltage and phase angle across the open breaker are within acceptable ranges and then permits a reclose. The second type makes an additional check that the system slip is within an acceptable range. The latter is applied at stations which are used to safely connect two parts of the system which may be asynchronous as part of the system restoration process.

Synchronizing check relays shall be used for all operator directed breaker reclosures at 240 kV and higher voltages. Settings for voltage, angle and slip are based on system studies.

Synchronizing check relaying is not applied for single pole auto-reclosing.

4.8 Distance or Impedance Protection

A minimum of two zones of distance or impedance protection shall be applied to all grid transmission lines.

The transient over/under reach characteristic of the distance protection is to be minimized without sacrificing the relay's speed and at the same time allow a Zone 1 reach of up to 85% of line length. Zone 2 relays shall be set to cover 125% of the protected line with a time delay set to coordinate with the local station breaker fail protection but shall not extend beyond the reach of the Zone 1 element of the adjacent line. The recommended Zone 2 timer is the breaker fail time for the voltage class plus a delay of 3 – 5 cycles to allow for local breaker re-trip. Longer time delays are permitted provided system stability in not impacted. Coordination of Zone 2 timer with remote breaker fail protection is a requirement. System studies may be required to define both Zone 2 and breaker fail times.

4.9 Current Comparison

Phase segregated current comparison or line differential protection shall be applied at 500 kV together with impedance back up. The protection shall be capable of single pole trip and reclose operation. The communications signaling equipment shall preferably be digital.

Line differential protection may be applied at lower voltages.

4.10 Stub Protection

During a line open condition with the station breakers closed, the bus between the station breakers and line disconnect for ring bus and breaker and a half/third configurations may not be protected. The line protection system shall be capable of protecting the open stub through the use of overcurrent protection.

This protection shall also function correctly for the case where the potential transformers for the line protection are located on the line side of line disconnect whether or not the line is energized from the remote end.

4.11 Protection Communication

For 500 kV and 240 kV transmission lines, two independent high-speed protection communication channels shall be provided. The communication speed shall conform to the primary tripping speeds dictated by Section 3.7 of this Standard.

Both permissive over reach transfer tripping (POTT) and permissive under reach transfer tripping (PUTT) protection schemes are applied to protect

100% of the transmission line. The preferred protection scheme for distance relaying is permissive over reach transfer trip using Zone 2 of the impedance relay.

For protection systems using Power Line Carrier (PLC), the protection system shall operate reliably in the presence of all likely environmental conditions including but not limited to hoar frost.

Protection signaling schemes shall be designed to have an overall availability of not less than 99.99%

4.12 LINE CONNECTED REACTORS

Line connected reactors are normally applied at 500 kV and may be applied at 240 kV to control the voltage on the line by absorbing line charging VArs. These reactors may be fixed or switched.

For single pole switched lines, the addition of a neutral reactor may be required to preclude a resonant condition during the single pole open condition.

For fixed reactors, the line shall be tripped for faults in the reactors. Sufficient protection shall be applied to allow the reactor fault to be identified. Operation of the line without the reactors shall be determined by system studies. If allowed, the reactor shall be equipped with motorized disconnects to allow the reactor to be isolated from the line. For reactor configurations that contain a neutral reactor for arc extinction, single pole trip and reclose shall be disabled during operation of the line without the line connected reactor. High-speed auto reclosure shall be blocked for all line connected reactor faults.

For four legged reactors, the use of an overall zero sequence differential protection is recommended coupled with individual differential protection on both the phase and ground connected reactors.

The protection application shall take note of the fact that the design of some line shunt reactors allows the reactor to partially saturate on energization as a means of controlling the line open circuit voltage rise. The protection shall be designed to operate reliably for this case.

For lines equipped with switched shunt reactors, the reactor protection shall isolate the reactor from the line for reactor faults. It may not be possible to isolate the reactor before the line protection operates to isolate the line. If the reactor configuration includes a neutral reactor for arc extinction, the reactor protection shall ensure the line protection trips three pole and, if permitted, recloses after the reactor has been isolated.

4.13 INTERCONNECTING TIE LINES

Tie lines interconnecting the AIES with other electrical systems shall comply with this Standard. Tie lines operated at 240 kV and higher shall be equipped for single pole tripping and auto-reclosing. Application is determined by system studies. The exception is lines connected to a back-to-back HVDC converters.

Power swing tripping shall normally be applied to all tie lines. The protection shall be set to trip if the swing enters Zone 1 of the impedance relay and block tripping for a preset time if the swing enters Zone 2.

Additional protection may be required because of the interconnection agreement. However, as a minimum this Standard shall be followed.

4.14 BROKEN AND OPEN CONDUCTOR PROTECTION

Two conditions are covered by this section. One, the line protection system shall be capable of detecting an open conductor condition. An open conductor condition includes loss of a jumper cable on a transmission structure or failure of one phase of a line disconnect to close. Two, the line protection system shall be capable of detecting a broken conductor lying on ground, e.g. a splice failure. Further, it is assumed this is a high-impedance fault, i.e. the ground is frozen.

Protection to allow the detection of broken and open conductors is recommended as an optional requirement.

4.15 SWITCH ONTO FAULT PROTECTION

Each line terminal shall be equipped with switch onto fault protection.

The preferred method is to use the higher zones of the impedance relay that have the ability to detect an overcurrent condition in the presence of zero or very low voltage.

High-speed auto reclose shall be blocked for this condition.

4.16 FAULT LOCATION

Numerical protection systems shall be equipped with a fault location algorithm.

5.0 STATIONS

5.1 PROTECTION APPLICATION

This section covers the application of protection to AIES stations. This includes all 500 kV, 240 kV and 138 kV stations on the AIES. Stations rated at 500 kV shall follow the requirements of this Standard. Stations rated at 240 kV shall use this Standard as recommended practice. Stations rated at 144/138 kV and lower shall use this Standard as a guide and may follow accepted utility practice.

Two independent high-speed protection systems shall be applied to all 138 kV and higher voltage transmission lines. At 500 kV, each protection system shall be completely independent of the other and shall be either from different manufacturers or use different protection principles. The reasons for this are to avoid type faults, ensure operation for evolving and simultaneous faults and avoid blind spots in the protection schemes. Each protection system shall be fed from its own secondary voltage and current source. Independent communication channels shall be employed for each protection system. It shall be possible to isolate one protection system for maintenance and testing without interfering with the operation of the transmission line and the other protection system in any way whatsoever. This isolation includes the requirements for end-to-end testing of the protection system. Operation of station connected equipment during this condition is at the Equipment Owner's discretion.

5.2 BUS LAYOUTS

The AESO will specify bus layouts in conjunction with the Equipment Owner for all AIES grid stations.

5.3 FAULT CONFIGURATION AND ZONES OF PROTECTION

Station protection shall be zoned from breaker to breaker. Sub zoning is required for parallel equipment connected to the same breaker. Equipment connected in parallel shall be equipped with automatic isolation devices in the form of motorized disconnects. The motorized disconnects shall be equipped with whip wires. The motorized disconnects shall be dimensioned to break the protected device's magnetizing current. The protection shall not operate for the motorized disconnect breaking magnetizing current. It shall be possible to restore automatically ring and breaker and half/third bus configurations after operation of the motorized disconnect isolates the faulted equipment. The only exceptions are breaker failure and bus faults.

Fault types are defined in Section 3.6 of this Standard.

Three phase faults to ground are considered rare. However, three phase faults because of maintenance grounds left connected to the system after maintenance do occur. The substation protection shall be designed to detect and isolate these faults.

5.4 AUTO-RECLOSING

Auto reclosing of station equipment is not permitted. If auto isolation of paralleled equipment is installed, auto reclosure of the breakers is an optional requirement.

5.5 SYNCHRONIZING CHECK RELAYING

Synchronizing check relays shall be used for all operator directed breaker reclosures as per Section 4.7 of this Standard for all AIES grid connected equipment.

5.6 TRANSFORMERS

In general, transformers over 10 MVA require three protection schemes, overall differential, back up overcurrent and mechanical protection schemes.

Transformers rated less than 10 MVA do not require differential protection. Transformers 10 MVA and above require variable percentage differential protection. Fusing of transformers 10 MVA and above or transformers with a primary voltage of 69 kV and higher is not permitted under any circumstances.

There shall be no overcurrent protection applied to the neutral of autotransformers. Neutral or zero sequence protection, if required, shall be supplied from the tertiary or from other protective device sources.

Thermal and gas protection systems shall be applied to all transformers. Gas protection shall preferably be both gas accumulation and gas surge. For gas surge, the transformer shall lockout trip and alarm for gas accumulation.

Two stages of thermal protection shall be applied. The first stage shall alarm and the second stage shall trip. The time between the alarm and trip stages shall allow the Equipment Owner to take action to unload the transformer. This protection shall non-lockout trip.

Optional oil level alarm and trip protection may be applied by the Equipment Owner. This protection shall trip lockout trip.

Station service transformers connected to the tertiary of autotransformers shall be directly connected to the tertiary and may be included in the transformer differential protection zone.

The following setting characteristics are given for reference.

Back up transformer overcurrent protection have the following recommended settings: 150% of the transformer's highest rating for time delayed operation and 133% of the transformer through fault current for the instantaneous element determined from $1/X_t$, where X_t is the transformer's voltage impedance.

5.6.1 Transformer-Ended Lines

For transformer-ended lines, the local station shall be equipped with direct transfer trip communication channels to trip the remote end breaker(s) and the remote station impedance protection shall have Zone 1 phase and ground elements set to look into the transformer or through the transformer to ensure high-speed clearing for a transformer bushing flashover.

5.7 BREAKER FAILURE PROTECTION

All breakers 138 kV and higher shall have breaker failure protection. All tripping devices shall initiate a current supervised breaker failure protection scheme. The requirement for breaker fail protection on the remote breaker of radial transmission lines shall be subject to a system study.

An overcurrent relay set below maximum load current in series with the protection trip contacts and supervised by the breaker open contacts shall be applied. Either the breaker open contact or the overcurrent supervision relay shall reset the breaker fail protection.

The overall tripping time measured from the instant of breaker fail initiation shall be:

- 500 kV 0.15 seconds (9 cycles)
- 240 kV 0.17 seconds (10 cycles)
- 138 kV 0.25 seconds (15 cycles)

Local station breaker fail shall initiate a re-trip of the failed breaker and a direct transfer trip to the remote station for transmission lines connected to the breaker fail protection. The remote station impedance relay Zone 2 timer shall be set to allow the breaker fail time to attempt to clear the fault locally.

For breakers equipped for and using single pole trip and reclose for transmission line faults, the breaker fail protection shall be capable of detecting a breaker fail during the single pole operation.

Breaker failure protection is not duplicated.

5.8 BUSBARS

Duplicate busbar protection is applied at 240 kV and above. Busbar protection is not duplicated at 138 kV. Busbar protection shall be of the voltage or current type and shall have a maximum fault detection time of 0.016 seconds (1 cycle).

The busbar protection shall trip all bus-connected breakers and initiate breaker fail protection. For bus-connected transformers, tripping of the transformer low voltage breakers is a requirement.

Busbar protection is not required for ring bus configurations. Protection applied to either the lines or transformers shall be capable of protecting the bus when the equipment is out of service. The protection must not operate during manual or automatic opening of the motorized disconnect.

5.9 CAPACITOR AND REACTOR BANKS

5.9.1 Shunt Capacitor Banks

Capacitor banks connected to the AIES solidly shall be solidly grounded at voltages of 69 kV and higher. Protection shall consist of overcurrent and overvoltage devices. For internally fused capacitor banks, voltage or current unbalance protection shall be applied to detect blown capacitor fuses. Internally fused capacitors shall have a visible means of detecting a failed can. Capacitor cans with external fusing shall have the fusing designed to ensure the fuse link is expelled to give a positive indication of the failed can. Differential protection is applied at the option of the Equipment Owner and is not an AESO requirement.

The design of the series/parallel elements shall allow two or more capacitor cans to fail before the bank is removed from service. An alarm shall be provided to indicate that one or more capacitor cans has failed.

For capacitor banks connected in parallel to the same breaker and energized via circuit switchers, individual protection shall be applied to allow detection of the faulted bank. A series reactor shall be installed in series with the capacitor bank to mitigate inrush and harmonic current effects.

Capacitor banks shall be equipped with auto-isolation equipment to remove the faulted capacitor bank from service after a fault condition on a paralleled capacitor bank. Capacitor banks shall remain de-energized for a minimum of 10 minutes after the bank has been isolated from the AIES. Auto-restoration of the capacitor bank is not permitted under any circumstances.

For stations where parallel capacitors banks are installed, the protection applied to each capacitor bank shall be immune from sympathetic tripping during switching of the second or higher banks when the first bank is in service.

5.9.2 Shunt Reactor Banks

Reactor banks connected to the AIES shall be solidly grounded at system voltages of 69 kV and higher.

Shunt reactor banks 10 MVAr and over shall be equipped as follows:

- Oil immersed reactors shall be equipped with differential and overcurrent protection systems. Thermal and gas protection for the reactor is also a requirement.

- Air core reactors shall be equipped with differential and overcurrent protection systems and may also be equipped with thermal protection.

Differential protection is not a requirement for reactor banks rated less than 10 MVAr.

For reactor banks connected in parallel to the same breaker and energized via circuit switchers, individual protection shall be applied to allow detection of the faulted bank.

Reactor banks shall be equipped with auto-isolation equipment to remove the reactor bank from service after a fault condition. Auto-restoration of the reactor bank is permitted.

5.10 STATIC VAR SYSTEMS

Protection of static VAr systems shall generally follow the manufacturer’s recommendations. Sufficient protection shall be incorporated into the control system to protect the AIES from the effects of prolonged full boost and/or full buck conditions. If this is not the case, supplemental protection may required.

For reactor/capacitor banks that are an integral part of the SVS, protection application shall conform to Section 5.9 of this Standard.

5.11 STATION SERVICE

Station service shall be supplied separately from the distribution system or from a low voltage bus within the station or from the tertiary of an autotransformer. Station service transformers connected to the tertiary of an autotransformers shall be directly connected and may be included in the differential protection of the autotransformer.

5.12 TRIP CIRCUITS

All trip circuit design shall be high-speed operation. Trip circuits shall not contain any intentional time delay whatsoever. Trip circuits shall be designed to preclude contact welding.

Trip circuit supervision is applied at 240 kV and higher voltages.

6.0 GENERATORS

6.1 GENERAL

This section covers protection applied to generators connected to the AIES grid and all generators 5 MVA, in aggregate, connected to the distribution system. The emphasis is on the effect the generator may have on the operation of the AIES grid during both contingency and non-contingency conditions. Protection applied by the Equipment Owner for the protection of their equipment is the responsibility of the Equipment Owner.

Protection applied shall be capable of protecting the generator from the effects of faults occurring on the AIES and protecting the AIES from the effects of faults occurring in the generator zone of protection.

This section contains protection that is applied to both protect the machine and the AEIS. Machine protection, where applicable, is the minimum required protection. It is the responsibility of the Equipment Owner to provide adequate protection for their equipment.

6.2 PROTECTION APPLICATION

Two independent protection systems shall be applied to the generator. The protection application may be divided into mechanical and electrical protection systems. In such case, two independent and separate mechanical and electrical protection systems shall be applied. Duplication of mechanical sensors or actuating devices is not required but may be applied at the discretion of the Equipment Owner

6.3 FAULT CONFIGURATION AND ZONES OF PROTECTION

The generator protection zone shall normally be from the high side breaker to the generator neutral. With the protection zoning it shall be possible to identify the faulted equipment, i.e. if the fault is in the generator or step up transformer. It shall be possible to restore automatically the high voltage station bus after opening of the generator or transformer motorized disconnect following successful detection and isolation of a fault.

The generator shall be protected from all fault types.

Three phase faults to ground are considered rare. However, three phase faults because of maintenance grounds left connected to the system after maintenance do occur. The generator protection shall be designed to detect and isolate these faults.

6.4 Generator Tripping

When a generator trip is issued the protection shall trip at a minimum the generator or high side breakers, as applicable, the excitation system and the turbine. Protection trips iniitated by system conditions or faults shall preferably have the generator go to speed no load. Where it is possible to energize or back feed the generator through the station service, the low voltage station service breakers shall also be tripped. This includes station service arrangements with high-speed bus transfer schemes.

For generators with a generator breaker between the generator and the generator step up transformer, it shall be possible to isolate the generator for generator faults without tripping the generator step up transformer high side breakers.

The design of the station service shall expressly preclude inadvertent energization of the generator through the station service bus.

6.5 Auto-reclosing

Auto-reclosing of breakers after a generator fault is not permitted under any circumstances.

6.6 Synchronizing

All synchronous generators shall be equipped with full synchronizing equipment and this equipment shall be capable of assuming full control of the generator governor and AVR during the synchronizing process.

Synchronizing check relaying is applied after isolation of a generator or generator step up transformer fault to restore the station bus under operator control.

6.7 Differential

Overall variable percentage differential protection shall be applied to the generator windings and generator step up transformer. The following configurations shall be applied:

- Overall differential protection for phase and ground faults from the neutral end of the generator to the high voltage side of the generator step up transformer.
- Generator differential protection for phase faults
- Generator differential protection for ground faults supplemented by 100% stator ground fault protection
- Generator step up transformer differential protection for phase and ground faults
- High voltage bus differential protection for both phase and ground faults. This protection must remain stable during the condition when

the generator step up transformer motorized disconnect is in the open position.

All of the above protection shall initiate lock out tripping.

The generator excitation transformer shall have its own protection. Generally, the excitation transformer is not included in the overall differential protection. Care must be exercised in the selection of the current transformer to ensure the current transformer can supply sufficient energy to operate the overcurrent protection.

6.8 GENERATOR MECHANICAL PROTECTION

Separate lockout tripping circuits may be applied for generator mechanical protection. This protection shall include, but not be limited to, temperature, speed, oil and vibration. The preferred application is two independent mechanical protection systems.

6.9 VOLTS/HERTZ

Volts/Hertz protection shall be included in the Automatic Voltage Regulator (AVR) equipment. This protection shall trip the AVR to manual and lower the excitation of the machine by a set percentage to allow the machine to continue running. Volts/Hertz protection is applied to the generator step up transformer and shall act as back up to the AVR protection and protect the generator step up transformer from over fluxing due to a mal functioning AVR. This protection shall coordinate with the transformer protection and be set to allow the AVR to act first.

6.10 STATOR

In addition to the differential protection applied to the generator, additional protection is required to protect against:

- Turn to turn faults
- Ground faults – 100% for generators greater than 5 MVA
- Ground faults – 95% for generator less than 5 MVA
- Stator overheating – detection by negative sequence
- Slow clearing system faults – the preferred method is back up impedance protection
- Over/under voltage conditions – as a back up to the AVR
- Over/under frequency conditions – as a back up to the governor

6.11 ROTOR

Rotor protection shall be applied to cover the following.

- Rotor ground faults
- Over heating due to unbalanced stator faults
- Over heating due to under excited operation

- Bearing current detection

It is noted that other protections applied for stator faults may inherently provide protection against rotor faults. Where such is the case, duplicate protection may not be required.

6.12 LOSS OF FIELD

An offset impedance relay shall be applied at the generator terminals to detect the loss of field condition. The preferred application is two zones of protection with Zone 1 instantaneous and Zone 2 timed.

6.13 OUT OF STEP

An out of step condition exists when the power swings traverses either the generator or generator step up transformer. This condition is similar to a power swing on the transmission system.

Impedance protection applied at the generator step up transformer terminals shall be applied. The impedance protection shall look into the generator step up transformer and generator. A shaped characteristic or blinders are required to prevent the protection from operating during normal machine operation.

6.14 REVERSE POWER

Reverse power flowing into the generator is to be detected and the generator removed from service. This condition is sometimes referred to as generator motoring. Detection is by either directional overcurrent or impedance. Setting of this protection is subject to the generator manufacturer’s recommendations.

Application of reverse power protection may be precluded for generators that can operate as synchronous condensers.

6.15 STATION SERVICE

The protection of the station service transformer shall conform to the protection of the substation transformers in Section 5.6 of this Standard.

6.16 AUTOMATIC VOLTAGE REGULATOR (AVR)

Protection shall be included in the AVR to prevent excessive over and under excitation of the generator, over fluxing and overvoltage. The AVR shall trip to manual and reduce the excitation to the machine by a fixed percentage. The purpose is the have the machine remain connected to the AIES and running at a fixed lower output. The power system stabilizer, if applied, shall be tripped during this operating condition.

6.17 Over/Under Frequency Generator Shedding

As a member of WECC, the AESO and hence the AIES participates in the Coordinated Off-Nominal Frequency and Restoration Plan. AESO OPP 804 sets outs the application requirements for generator over/under frequency requirements.

Generators that do not meet the requirements of OPP 804 must automatically trip load in addition to that required in Section 7.3 of this Standard to match anticipated generation loss at comparable frequencies.

6.18 Potential Transformer

Potential transformers used for the protection of generators shall have blown fuse protection applied.

6.19 Alarm and Trip

For generator protection schemes applied to manned stations, alarming for abnormal operating conditions is permitted to give the station operators time to correct the potential trip condition.

Protection systems in manned stations may employ delayed tripping for this condition. However, blocking of the protection systems is not permitted under any circumstances.

6.20 Distribution Connected Generation

This section details protection requirements for distribution connected generation at the point of interconnection to the AIES. Protection requirements include, but are not limited to, phase and ground directional overcurrent protection. Anti-islanding protection with transfer tripping may be a requirement. Depending on the point of synchronization, synchronizing check relaying an/or live line close blocking supervision protection are requirements.

Distribution lines connected to distribution connected generation require protection to ensure the AIES is protected from the effects of faults and abnormal operating conditions arising from, associated with or contributed by the distribution connected generation.

Distribution generation 5 MW or greater in aggregate connected at 69 kV and below is subject to special protection application considerations since the lines are effectively grid transmission facilities. Lower voltage express feeder lines, which connect the distribution generation through a transformer to the AIES are covered. Protection of these lines shall be jointly defined by the AESO and Equipment Owner.

7.0 SYSTEM PROTECTION

7.1 PROTECTION APPLICATION

These protection schemes are applied to protect the AIES from the effects of prolonged operation during abnormal operation conditions such as over/under frequency and over/under voltage. These schemes may be time delayed and trip non-lockout and allow the system operator to re-energize remotely the equipment after the abnormal condition has been remedied.

7.2 UNDER/OVERVOLTAGE

The requirements for under/overvoltage protection are subject to detailed system studies and the protection devices and settings are normally established by the AESO in conjunction with the Equipment Owner.

7.3 UNDER/OVERFREQUENCY

As a member of WECC, the AESO and hence the AIES participates in the Coordinated Off-Nominal Frequency and Restoration Plan. AESO OPP 804 sets outs the application requirements for generator over/under frequency requirements.

Under/overfrequency protection is mandated by AIES membership in the WECC. This load shedding/restoration plan is contained in AESO OPP 804. The AESO will coordinate the amount of load shed/restored for the AIES. The use of intermittent load is not permitted for load shedding.

A contracted amount of load is shed at 59.5 Hz as part of RAS. This load is not a part of the WECC off nominal frequency load shedding program.

Only solid state or microprocessor based frequency relays shall be applied to the AIES. The relays must incorporate a definite time characteristic. The use of inverse time and rate of frequency relaying is not permitted. The preferred relay plus breaker operating time is 12 cycles (0.2 sec), however the maximum allowable relay plus breaker time is 14 cycles (0.23 sec). All relays shall operate reliably down to and including 80% of nominal voltage.

Automatic restoration of load is permitted under the following conditions:

- System frequency at 59.95 Hz and stable
- Sufficient generation on line to restore the Area Control Error (ACE) within 10 minutes
- 30 minutes has passed since the disturbance was initiated
- Load restoration at the rate of 2% system load at intervals of not less than 5 minutes

7.4 INTERCONNECTING TIE LINE UNDER FREQUENCY

Tripping of ac tie lines interconnecting other systems is permitted at frequencies at or below 57.9 Hz. Tripping of tie lines must comply with the relevant WECC policy and are subject to the agreements between the interconnected entities.

7.5 POWER SWING DETECTION, BLOCKING AND TRIPPING

The requirements for power swing detection, blocking and tripping protection are subject to detailed system studies and the protection devices and settings are normally established by the AESO in conjunction with the Equipment Owner.

All impedance protection shall be equipped with power swing detection protection. Power swing detection shall be applied to transmission lines that have been shown to have a system zero. A system zero is defined as an apparent three phase short circuit forward of the impedance relays at either end of the transmission line under study. That is, during a swing condition a voltage reversal occurs at either the sending or receiving end.

The method of determining if a system zero exits is as follows:

- Remove the line under study
- Apply a three fault at both the sending and receiving end busses
- From the fault study determine the Thévenin equivalent impedances, a flat start is recommended
- Sum the three impedances and divide by 2
- Determine if the resulting impedance lies on the protected line
- If yes, power swing detection is required
- If no, power swing detection is not required
- If the system zero lies within +/- 10% of the line terminal, power swing detection is required and a system study is required to determine the application, i.e. block and/or trip.

This application shall consider both blocking and tripping applications. Blocking shall generally be applied for slow-speed swings that enter the Zone 2 and higher impedance relay characteristics. A timing circuit shall be incorporated that will trip via the Zone 2 element if the swing does not reset the timer after a predetermined time. Power swings that enter Zone 1 shall result in a trip condition. Auto reclose shall not be applied. Power swing blocking shall not be applied without a tripping function.

Dependent upon breaker rating and system conditions, tripping for power swings entering Zone 1 may be delayed until the swing exists Zone 1. This is an equipment application concern.

The above procedure identifies the probable requirements for power swing detection. Additional transient studies by the Equipment Owner are required to confirm the requirements and protection settings for this protection.

7.6 GENERATOR AND LOAD REMEDIAL ACTION AND SPECIAL PROTECTION SCHEMES

Remedial Action Schemes (RAS) are applied to detect abnormal operating conditions that, if left unactioned, could cause system stability or equipment concerns. These RAS trip a predetermined amount of load and/or generation through the use of high-speed communication circuits. Duplication of the communication circuits may be a requirement. This requirement will be determined by the AESO. Application of RAS protection is dictated by system studies conducted by the AESO. Three examples are given below.

Special Protection Schemes (SPS) are similar to RAS and are applied at the direction of the AESO to detect and mitigate against the effects of abnormal operating conditions that may be the result of operating conditions or faults external to the AIES. These protection schemes may be required to mitigate, on a temporary basis, abnormal system conditions on the AIES. An example of the latter would be a generator or load that is connected to the AIES before sufficient transmission is in place to serve that generation or load.

During conditions of high import or export on the 500 kV transmission line to BC, loss of the line may put the AIES at danger of either an under or over frequency condition. During this condition, it may be necessary to shed load or generation in order for the AIES to remain stable. Such protection, when applied, shall detect loss of the 500 kV line and trip a pre-determined amount of load or generation.

In the Fort McMurray area there exists an excess of generation compared with transmission capacity. Loss of one 240 kV line may require arming of a remedial action scheme to trip generation. Curtailment by operating policy may also be a requirement.

In the southwest part of Alberta, there is a large concentration of wind generation compared with transmission capacity. Loss of a transmission line may require tripping of generation. Curtailment by operating policy may also be a requirement.

7.7 TRANSMISSION CONGESTION

Transmission congestion is deemed to be an operating concern and additional or special protection is not applied to detect or mitigate against this condition. Transmission congestion is usually mitigated by running generation out of merit. Protection applied to transmission lines must be capable of detecting the long-term effects of abnormal operating condition and take mitigative action.

7.8 LINE LOADING MONITORS

The application of line loading monitors shall be determined by the AESO in conjunction with the Equipment Owner.

8.0 HVDC PROTECTION

8.1 GENERAL

This section covers protection applied to HVDC stations connected to the AIES. The emphasis is on protecting the ac system from the effects the HVDC station may have on the operation of the AIES during both contingency and non-contingency conditions. Protection applied by the Equipment Owner for the protection of their equipment is the responsibility of the Equipment Owner.

Protection applied shall be capable of protecting the HVDC station from the effects of faults occurring on the AIES and protecting the AIES from faults occurring in the HVDC station zone of protection.

8.2 RECTIFIER / INVERTER

The protection of the dc side of the HVDC station is the responsibility of the Equipment Owner. The protection applied to the HVDC equipment must mitigate against abnormal voltages and currents in the conversion equipment and the effects these voltages and currents have in the connected ac system. The Equipment Owner must ensure that faults and misoperation of the dc equipment are isolated within the dc converter and control equipment and must not cause a disturbance on the connected ac system. That is, cascade tripping for dc faults or control malfunctions in the dc system must not occur.

8.3 AC SYSTEM

For this Standard, the ac system consists of all equipment connected to the ac system and operating with ac voltages and currents. This includes the transmission lines connected to the HVDC station, the converter transformers, ac filters and interconnecting station busbar.

Protection applied on the ac side of the HVDC station must take into account the harmonics generated as a result of the conversion process.

8.3.1 AC Transmission Lines

Protection applied to the ac transmission lines must recognize that the converter station has no inertia and to the applied distance protection, the station looks like a load. Therefore, line differential protection is usually applied to protect the connected ac transmission lines. Overreaching distance protection may be applied at the remote terminal set to look into the converter transformer with a direct transfer trip scheme for the local breaker at the HVDC station.

8.3.2 Converter Transformer

The converter transformer protection consists of the same or similar protection applied to station transformers as specified in Section 5.6 of this Standard. The protection application must take into consideration the harmonics generated because of the conversion process, either inversion or rectification.

Depending upon the HVDC station design, the converter transformer may be a three or four winding design. The primary winding connects the valve groups the ac system. The two secondary windings are usually configured wye and delta. A fourth winding, the tertiary, connects the ac filter banks and any supporting reactor capacitor banks.

8.3.3 AC Filter Banks

Modern HVDC stations employ 12-pulse converter technology. Consequently, ac harmonics at frequencies of (12n +/- 1) times the 60 Hz fundamental frequency are generated, where n is an integer. AC filter banks connected to the ac side of the converter station provide a means of sinking the harmonics produced during the conversion process and produce a portion of the reactive power required for the conversion process.

Protection of the ac filter banks is similar to the protection of shunt capacitor banks described in Section 5.9 of this Standard with the additional requirement that the protection must not constrain the harmonic requirements of the station.

8.3.4 Capacitor/Reactor Banks

Capacitors/Reactor banks shall be protected as per Section 5.9 of this Standard.

8.4 BREAKER FAILURE PROTECTION

Breaker failure protection as specified in Section 5.7 of this Standard shall be applied to all breakers 138 kV and higher in the ac station.

8.5 DYNAMIC OVERVOLTAGES

Dynamic overvoltages occur during switching of the filter banks and shunt capacitor banks. In addition, the shunt connected capacitor banks can increase the remote end open circuit voltages. Overvoltage protection is required at both the HVDC station and the remote ends of the ac transmission lines connected to the HVDC station.

8.6 SUB SYNCHRONOUS TORSIONAL ANALYSIS

The Equipment Owner shall perform studies and provide information to the AESO on whether the proposed converter station can activate potentially damaging sub synchronous torsional interactions with existing generators or large motors in the vicinity of the HVDC station. If it is determined that the potential risk is severe, the AESO will in consultation with the Equipment Owner determine the necessary protection to be implemented.

9.0 REPORTING AND RECORDING

9.1 GENERAL

This section covers the reporting and recording of protection application and operation. The Equipment Owner shall maintain records of protection application as outlined below. The Equipment Owner shall install disturbance recording equipment integral to the protection equipment. The AESO has the right to request application and/or disturbance reports from the Equipment Owner. The Equipment Owner shall comply with any request the AESO makes for the application and/or disturbance reports. Generally, the AESO will limit the request for disturbance reports to disturbances resulting in loss of load or generation of 100 MVA or more.

9.2 TIME REQUIREMENTS

When requested by the AESO, the Equipment Owner shall provide all requested information to the AESO within three (3) business days of the request being made in writing.

9.3 APPLICATION REPORT TO AESO

The Equipment Owner shall document all protection applied to AIES. Documentation shall include:

- Statement of conformance with this Standard
- Statement of non-conformance with this Standard, the areas of non-conformance and the reasons why.
- Protected equipment characteristics.
- Protection and control single lines.
- All manuals for the protection system applied.
- All protection devices complete with their settings.

The protection application report is to be signed and stamped by an APEGGA member in good standing. For work completed outside of Alberta by a non APEGGA member, the Equipment Owner shall review the work and fix his or her stamp to work certifying that the work is in correct and in compliance with this Standard.

9.4 MATHEMATICAL MODELS

At the request of the AESO, the Equipment Owner shall make available to the AESO mathematical models for protective equipment applied to the AIES. Should the protective equipment manufacturer deem this information proprietary, the AESO will enter into a non-disclosure agreement with the protective equipment manufacturer.

These models shall conform to the relevant IEEE/ANSI or IEC standards. Sufficient information shall be provided to allow the AESO to incorporate these models into the AESO power system modeling programs and other software as applicable.

The mathematical models are to be used to determine the steady state application of the protective device or system. Determination of the applicability of the protective device or system under transient conditions shall be by either system or field test, model power system or disturbance recordings from the protective device or other devices.

9.5 DATA FROM OPERATION

All numerical protection systems shall be equipped with recording devices that record the voltages and currents and all analog relay operations seen during a fault condition and any other abnormal operating condition that initiates a protection device pick up, whether the device operates or not and all input and output contacts from the protection device. A minimum of three cycles of pre-fault data shall be included in the recording.

Waveforms and event data shall be time tagged to GPS time standard and the COMTRADE format is preferred.

Implementation of the following paragraph of Section 9.5 is deferred until a later date.

Software required for viewing and manipulating the recorded data from the protective recording devices shall be made available to the AESO at no cost to the AESO.

9.6 REQUIREMENTS FOR TESTING

The Equipment Owner shall perform sufficient tests on the protection equipment to confirm the protection equipment is suitable for the designed application.

The AESO at its sole option may elect to witness the testing of protection applied to generators greater than 100 MVA and lines at voltages of 240 kV and greater. The Equipment Owner shall notify the AESO five (5) business days before the protection applied to the generators greater than 100 MVA and lines at voltages of 240 kV and greater are being tested.

The AESO may request the Equipment Owner to provide the test reports to the AESO. The Equipment Owner shall supply the requested reports to the AESO within five (5) business days of being requested to do so.

10.0 DEFINITIONS

In this Standard, the following terms have the meanings assigned to them. For the sake of clarity, the defined terms are capitalized throughout the Protection Standard.

- Applications Engineering Summary – an engineering report provided by the Equipment Owner that details the protection application deviations from this Standard and technical reasons for the deviations.
- Auto Isolation – refers to the automatic isolation of faulted equipment usually by motorized disconnect after a fault on the equipment has been successfully detected and isolated by a breaker.
- Auto Restoration – refers to the automatic restoration of unfaulted equipment after other faulted station equipment has been auto isolated.
- Backup Protection – refers to protection applied that operates slower than primary protection and operates to isolate faulted equipment form the AIES.
- Bulk Electric System – refers to the portion of an electric utility system, which encompasses the electrical generation resources, transmission lines, interconnections with neighboring systems and associated equipment, generally operated at voltages of 100 kV or higher and includes the low voltage terminals of equipment with a primary voltage of 100 kV or higher.
- Cascade Tripping – refers to the uncontrolled successive loss of system elements triggered by an incident at any location and for this Standard refers to the tripping of adjacent or remote terminal equipment that is not part of the protected equipment zone of protection.
- Credible Faults – refers to any fault configuration that if left undetected has the potential to either destroy the protected equipment or cause loss of load, generation or transmission.
- Cross Country Fault – refers to two faults that occur simultaneously, are not on the same equipment, and are separated by a distance. For example, lightning strikes to two transmission lines.
- Direct Tripping – refers to the issuing of a breaker trip signal from a protective device without the intervention of any other device.
- Double Contingency – refers to an event that has two separate causes.
- Effectively Grounded – refers to a system configuration that has the single phase to ground fault current equal to the three phase fault current and defined by the ratio of the zero sequence reactance to the positive sequence reactance being equal to or less than three.

- Equipment Owner – refers to an entity that owns the physical asset that is to be protected by this Standard and refers to the entity responsible for any or all of the following; design, construction, operation, maintenance.

- High-speed Reclosing – refers to the automatic reclosing of transmission lines after successful detection of a line fault without the use of synchronizing check relaying.

- Lockout – refers to a protection system that after operation prevents the protected equipment's breakers from closing without manual to reset the lockout relay.

- Non Lockout – refers to a protection system that after operation permits the equipment to be re-energized either automatically or manually.

- Primary Protection – refers to the high-speed protection that is relied upon to detect the fault condition first.

- Secondary Protection – refers to protection that operates at the same or slower speed as the primary protection and backs up the primary protection.

- Single Contingency – refers to a single event.

- System Protection – refers to protection applied to the AIES to detect an abnormal operating condition that is not a fault condition but may be the result of fault condition. The protection may be applied to detect a wide area or local condition.

- System Load Shed Scheme – refers to the requirement by WECC to remove load during an underfrequency condition at specified underfrequencies and for specified load amounts.

- Transfer Tripping – refers to the issuing of a trip signal that may be supervised by an other protection system which is usually associated with communication-aided protection schemes.

APPENDIX I WECC PLANNING STANDARDS

The WECC/NERC Planning Standards are located at:
http://www.wecc.biz/committees/PCC/RS/documents/WECC-NERC_Planning%20Standards_4-10-03.pdf

Section III System Protection and Control is reproduced in the following paragraphs. This Appendix forms part of the AESO Protection Standard. Where this Appendix is in conflict with the Protection Standard, the Protection Standard shall take precedence.

III. System Protection and Control

Discussion

Protection and control systems are essential to the reliable operation of the interconnected transmission networks. They are designed to automatically disconnect components from the transmission network to isolate electrical faults or protect equipment from damage due to voltage, current, or frequency excursions outside of the design capability of the facilities. Control systems are those systems that are designed to automatically adjust or maintain system parameters (voltages, facility loadings, etc.) within pre-defined limits or cause facilities to be disconnected from or connected to the network to maintain the integrity of the overall bulk electric systems.

The objectives for protection and control systems generally include:

- **DEPENDABILITY** - a measure of certainty to operate when required,
- **SECURITY** - a measure of certainty not to operate falsely,
- **SELECTIVITY** - the ability to detect an electrical fault and to affect the least amount of equipment when removing or isolating an electrical fault or protecting equipment from damage, and
- **ROBUSTNESS** - the ability of a control system to work correctly over the full range of expected steady-state and dynamic system conditions.

A reliable protection and control system requires an appropriate level of protection and control system redundancy. Increased redundancy improves dependability but it can also decrease security through greater complexity and greater exposure to component failure.

Protection and control system reliability is also dependent upon sound testing and maintenance practices. These practices include defining what, when, and how to test equipment calibration and operability, performing preventive maintenance, and expediting the repair of faulty equipment.

Diagnostic tools, such as fault and disturbance recorders, can provide a record of protection and control system performance under various transmission system conditions. These records are often the only means to diagnose protection and control anomalies. Such information is also critical in determining the causes of system disturbances, the sequence of disturbance events, and developing necessary corrective and preventive actions. In some instances, these records provide information about incipient conditions that would lead to future transmission system problems.

Coordination of protection and control systems is vital to the reliability of the transmission networks. The reliability of the transmission network can be jeopardized by unintentional and unexpected automatic control actions or loss of facilities caused by misoperation or uncoordinated protection and control systems. If protection and control systems are not properly coordinated, a system disturbance or contingency event could result in the unexpected loss of multiple facilities. Such unexpected consequences can result in unknowingly operating the electric systems under unreliable conditions including the risk of a blackout, if the event should occur.

The design of protection and control systems must be coordinated with the overall design and operation of the generation and transmission systems. Proper coordination requires an understanding of:

- The characteristics, operation, and behavior of the generation and transmission systems and their protection and control,
- Normal and contingency system conditions, and
- Facility limitations that may be imposed by the protection and control systems.

Coordination requirements are specifically addressed in the areas of communications, data monitoring, reporting, and analysis throughout the **Standards, Measurements, and Guides** under System Protection and Control (III).

The **NERC Planning Standards, Measurements, and Guides** pertaining to System Protection and Control (III) are provided in the following sections:

A. Transmission Protection Systems
B. Transmission Control Devices
C. Generation Control and Protection
D. Underfrequency Load Shedding
E. Undervoltage Load Shedding
F. Special Protection Systems

These **Standards, Measurements, and Guides** shall apply to all protection and control systems necessary to achieve interconnected transmission network performance as described in the Standards on System Adequacy and Security (I) in this report.

A. Transmission Protection Systems

Introduction

The goal of transmission protection systems is to ensure that faults within the intended zone of protection are cleared as quickly as possible. When isolating an electrical fault or protecting equipment from damage, these protection systems should be designed to remove the least amount of equipment from the transmission network. They should also not erroneously trip for faults outside the intended zones of protection or when no fault has occurred. The need for redundancy in protection systems should be based on an evaluation of the system consequences of the failure or misoperation of the protection system and the need to maintain overall system reliability.

Standards

S1. Transmission protection systems shall be provided to ensure the system performance requirements as defined in the I.A. Standards on Transmission Systems and associated Table I.

S2. Transmission protection systems shall provide redundancy such that no single protection system component failure would prevent the interconnected transmission systems from meeting the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I.

S3. All transmission protection system misoperations shall be analyzed for cause and corrective action.

S4. Transmission protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Transmission or protection system owners shall review their transmission protection systems for compliance with the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I. Any noncompliance shall be documented, including a plan for achieving compliance. Documentation of protection system reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S1)

M2. Where redundancy in the protection systems due to single protection system component failures is necessary to meet the system performance requirements of the I.A. Standards on Transmission Systems and associated Table I, the transmission or protection system owners shall provide, as a minimum, separate ac current inputs and separately fused dc control voltage with new or upgraded protection system installations. Breaker failure protections need not be duplicated. (S2)

Each Region shall also develop a plan for reviewing the need for redundancy in its existing transmission protection systems and for implementing any required redundancy. Documentation of the protection system redundancy reviews shall be provided to NERC, the Regions, and those entities responsible for the reliability of the interconnected transmission systems on request. (S2)

M3. Each Region shall have a procedure for the monitoring, review, analysis, and correction of transmission protection system misoperations. The Regional procedure shall include the following elements:
1. Requirements for monitoring and analysis of all transmission protective device misoperations.
2. Description of the data reporting requirements (periodicity and format) for those misoperations that adversely affect the reliability of the bulk electric systems as specified by the Region.
3. Process for review, follow up, and documentation of corrective action plans for misoperations.
4. Identification of the Regional group responsible for the procedure and the process for Regional approval of the procedure.
5. Regional definition of misoperations.

Documentation of the Regional procedure shall be maintained and provided to NERC on request (within 30 days). (S3)

M4. Transmission protection system owners shall have a protection system maintenance and testing program in place. This program shall include protection system identification, schedule for protection system testing, and schedule for protection system maintenance. Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S4)

M5. Transmission protection system owners shall analyze all protection system misoperations and shall take corrective actions to avoid future misoperations.

Documentation of the misoperation analyses and corrective actions shall be provided to the affected Regions and NERC on request (within 30 days) according to the Regional procedures of Measurement III.A. S3, M3.

Guides

G1. Protection systems should be designed to isolate only the faulted electric system element(s), except in those circumstances where additional elements must be removed from service intentionally to preserve electric system integrity.

G2. Breaker failure protection systems, either local or remote, should be provided and designed to remove the minimum number of elements necessary to clear a fault.

G3. The relative effects on the interconnected transmission systems of a failure of the protection systems to operate when required versus an unintended operation should be weighed carefully in selecting design parameters.

G4. Protection systems and their associated maintenance procedures should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling.

G5. Physical and electrical separation should be maintained between redundant protection systems, where practical, to reduce the possibility of both systems being disabled by a single event or condition.

G6. Communications channels required for protection system operation should be either continuously monitored, or automatically or manually tested.

G7. Models used for determining protection settings should take into account significant mutual and zero sequence impedances.

G8. The design of protection systems, both in terms of circuitry and physical arrangement, should facilitate periodic testing and maintenance.

G9. Protection and control systems should be functionally tested, when initially placed in service and when modifications are made, to verify the dependability and security aspects of the design.

G10. Protection system applications should be reviewed whenever significant changes in generating sources, transmission facilities, or operating conditions are anticipated.

G11. The protection system testing program should include provisions for relay calibration, functional trip testing, communications system testing, and breaker trip testing.

G12. Generation and transmission protection systems should avoid tripping for stable power swings on the interconnected transmission systems.

G13. When two independent protection systems are required, dual circuit breaker trip coils should be considered.

G14. Where each of two protection systems are protecting the same facility, the equipment and communications channel for each system should be separated physically and designed to minimize the risk of both protection systems being disabled simultaneously by a single event or condition.

G15. Automatic reclosing or single-pole switching of transmission lines should be used where studies indicate enhanced system stability margins are necessary. However, the possible effects on the systems of reclosure into a permanent fault need to be considered.

G16. Protection system applications and settings should not normally limit transmission use.

G17. Application of zone 3 relays with settings overly sensitive to overload or depressed voltage conditions should be avoided where possible.

B. Transmission Control Devices

Introduction

Certain transmission devices are planned and designed to provide dynamic control of electric system quantities, and are usually employed as solutions to specific system performance issues. They typically involve feedback control mechanisms using power electronics to achieve the desired electric system dynamic response. Examples of such equipment and devices include: HVDC links, active or real power flow control and reactive power compensation devices using power electronics (e.g., unified power flow controllers (UPFCs), static var compensators (SVCs), thyristor-controlled series capacitors (TCSCs), and in some cases mechanically switched shunt capacitors and reactors.

In planning and designing transmission control devices, it is important to consider their operation within the context of the overall interconnected systems over a variety of operating conditions. These control devices can be used to avoid degradation of system performance and cascading outages of facilities. If not properly designed, the feedback controls of these devices can become unstable during weakened system conditions caused by disturbances, and can lead to modal interactions with other controls in the interconnected systems.

Standard

S1. Transmission control devices shall be planned and designed to meet the system performance requirements as defined in the I.A. Standards of the Transmission Systems and associated Table I. These devices shall be coordinated with other control devices within a Region and, where appropriate, with neighboring Regions.

Measurements

M1. When planning new or substantially modified transmission control devices, transmission owners shall evaluate the impact of such devices on the reliability of the interconnected transmission systems. The assessment shall include sufficient modeling of the details of the dynamic devices and encompass a variety of contingency system conditions. The assessment results shall be provided to the Regions and NERC on request. (S1)

M2. Transmission owners shall provide transmission control device models and data, suitable for use in system modeling, to the Regions and NERC on request. Preliminary data on these devices shall be provided prior to their in-service dates. Validated models and associated data shall be provided following installation and energization. (S1)

M3. The transmission owners or operators shall document and periodically (at least every five years or as required by changes in system conditions) review the settings and operating strategies of the control devices. Documentation shall be provided to the Regions and NERC on request. (S1)

Guides

G1. Coordinated control strategies for the operation of transmission control devices may require switching surge studies, harmonic analyses, or other special studies.

G2. For HDVC links in parallel with ac lines, supplementary control should be considered so that the HDVC links provide synchronizing and damping power for interconnected generators. Use of HDVC links to stabilize system ac voltages should be considered.

C. Generation Control and Protection

Introduction

Generator excitation and prime mover controls are key elements in ensuring electric system stability and reliability. These controls must be coordinated with generation protection to minimize generator tripping during disturbance-caused abnormal voltage, current, and frequency conditions. Generators are the primary method of electric system dynamic voltage control, and therefore good performance of excitation equipment (exciter, voltage regulator, and, if applicable, power system stabilizer) is essential for electric system stability. Prime mover controls (governors) are the primary method of system frequency regulation.

Generator control and protection must be planned and designed to provide a balance between the need for the generator to support the interconnected electric systems during abnormal conditions and the need to adequately protect the generating equipment from damage. Unnecessary generator tripping during a disturbance aggravates the loading conditions on the remaining online generators and can lead to a cascading failure of the interconnected electric systems.

Accurate data that describes generator characteristics and capabilities is essential for the studies needed to ensure the reliability of the interconnected electric systems. Protection characteristics and settings affecting electric system reliability must be provided as requested.

Standards

S1. All synchronous generators connected to the interconnected transmission systems shall be operated with their excitation system in the automatic voltage control mode unless approved otherwise by the transmission system operator.

S2. Generators shall maintain a network voltage or reactive power output as required by the transmission system operator within the reactive capability of the units. Generator step-up and auxiliary transformers shall have their tap settings coordinated with electric system voltage requirements.

S3. Temporary excursions in voltage, frequency, and real and reactive power output that a generator shall be able to sustain shall be defined and coordinated on a Regional basis.

S4. Voltage regulator controls and limit functions (such as over and under excitation and volts/hertz limiters) shall coordinate with the generator's short duration capabilities and protective relays.

S5. Prime mover control (governors) shall operate with appropriate speed/load characteristics to regulate frequency.

S6. All generation protection system trip misoperations shall be analyzed for cause and corrective action.

S7. Generation protection system maintenance and testing programs shall be developed and implemented.

Measurements

M1. Generation equipment owners shall provide, upon request, the Region and transmission system operator a log that specifies the date, duration, and reason for each period when the generator was not operated in the automatic voltage control mode. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S1)

M2. When requested by the transmission system operator, the generating equipment owner shall provide a log that specifies the date, duration, and reason for a generator not maintaining the established network voltage schedule or reactive power output. (S2)

M3. The generation equipment owner shall provide the transmission system operator with the tap settings and available ranges for generator step-up and auxiliary transformers. When tap changes are necessary to coordinate with electric system voltage requirements, the transmission system operator shall provide the generation equipment owner with a report that specifies the required tap changes and technical justification for these changes. The procedures for reporting the data shall address generating unit exemption criteria and shall require documentation of those generating units that are exempt from a portion or all of these reporting requirements. (S2)

M4. When requested, generating equipment owners shall provide the Region and transmission system operator with the operating characteristics of any generator's equipment protective relays or controls that may respond to temporary excursions in voltage, frequency, or loading with actions that could lead to tripping of the generator. The more common protective relays include volts per hertz, loss of excitation, underfrequency, overspeed, and backup distance. (S3)

M5. Upon request, generating equipment owners shall provide the Region and transmission system operator with information that describes how generator controls coordinate with the generator's short-term capabilities and protective relays. (S4)

M6. Overexcitation limiters, when used, shall be coordinated with the thermal capability of the generator field winding. After allowing temporary field current overload, the limiter shall operate through the automatic ac voltage regulator to reduce field current to the continuous rating. Return to normal ac voltage regulation after current reduction shall be automatic. The overexcitation limiter shall be coordinated with overexcitation protection so that overexcitation protection only operates for failure of the voltage regulator/limiter. (S4)

M7. Upon request, generating equipment owners shall provide the Region or transmission system operator with information that describes the characteristics of the speed/load governing system. Boiler or nuclear reactor control shall be coordinated to maintain the capability of the generator to aid control of system frequency during an electric system disturbance to the extent possible while meeting the safety requirements of the plant. Nonfunctioning or blocked speed/load governor controls shall be reported to the Region and transmission system operator. (S5)

M8. Each Region shall have a process in place for the monitoring, notification, and analysis of all generation protection trip operations. Documentation of protection trip misoperations shall be provided to the affected Regions and NERC on request. (S6)

M9. Generation equipment owners shall have a generation protection system maintenance and testing program in place. Documentation of the implementation of protection system maintenance and testing shall be provided to the appropriate Regions and NERC on request. (S7)

Guides

G1. Power system stabilizers improve damping of generator rotor speed oscillations. They should be applied to a unit where studies have determined the possibility of unit or system instability and where the condition can be improved or corrected by the application of a power system stabilizer. Power system stabilizers should be designed and tuned to have a positive damping effect on local generator oscillations and on inter-area oscillations without deteriorating turbine/generator shaft torsional oscillation damping.

G2. Generators and turbines should be designed and operated so that there is additional reactive power capability that can be automatically supplied to the system during a disturbance.

G3. Generator control and protection should be periodically tested to the extent practical to ensure the generator plant can provide the designed control, and operate without tripping for specified voltage, frequency, and load excursions. Control responses should be checked periodically to validate the model data used in simulation studies.

G4. New or upgraded excitation equipment should consider high initial response, as inherent in brushless or static exciters.

G5. Generator step-up transformer and auxiliary transformers should have tap settings that are coordinated with electric system voltage control requirements and which do not limit maximum use of the reactive capability (lead and lag) of the generators.

G6. Prime mover control (governors) should operate freely to regulate frequency. In the absence of Regional requirements for the speed/load control characteristics, governor droop should generally be set at 5% and total governor deadband (intentional plus unintentional) should generally not exceed +/- 0.06%. These characteristics should in most cases ensure a coordinated and balanced response to grid frequency disturbances. Prime movers operated with valves or gates wide open should control for overspeed/overfrequency.

G7. Prime mover overspeed controls to the extent practical should be designed and adjusted to prevent boiler upsets and trips during partial load rejection characterized by abnormally high system frequency.

G8. Generator voltage regulators to the extent practical should be tuned for fast response to step changes in terminal voltage or voltage reference. It is preferable to run the step change in voltage tests with the generator not connected to the system so as to eliminate the system effects on the generator voltage. Terminal voltage overshoot should generally not exceed 10% for an open circuit step change in voltage test.

G9. New or upgraded excitation equipment to the extent practical should have an exciter ceiling voltage that is generally not less than 1.5 times the rated output field voltage.

G10. Power plant auxiliary motors should not trip or stall for momentary undervoltage associated with the contingencies as defined in Categories A, B, and C of the I.A. Standards on Transmission Systems, unless the loss of the associated generating unit(s) would not cause a violation of the contingency performance requirements.

D. Underfrequency Load Shedding

Introduction

A coordinated automatic underfrequency load shedding (UFLS) program is required to help preserve the security of the generation and interconnected transmission systems during major declining system frequency events. Such a program is essential to minimize the risk of total system collapse, protect generating equipment and transmission facilities against damage, provide for equitable load shedding (interruption of electric supply to customers), and help ensure the overall reliability of the interconnected systems.

Load shedding resulting from a system underfrequency event should be controlled so as to balance generation and customer demand (load), permit rapid restoration of electric service to customer demand that has been interrupted, and when necessary re-establish transmission interconnection ties.

Standards

S1. A Regional UFLS program shall be planned and implemented in coordination with other UFLS programs, if any, within the Region and, where appropriate, with neighboring Regions. The Regional UFLS program shall be coordinated with generation control and protection systems, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control systems.

Measurements

M1. Each Region shall develop, coordinate, and document a Regional UFLS program, which shall include the following:

a. Requirements for coordination of UFLS programs within the subregions, Region, and, where appropriate, among Regions.

b. Design details including size of coordinated load shedding blocks (% of connected load), corresponding frequency set points, intentional delays, related generation protection, tie tripping schemes, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UFLS programs.

c. A Regional UFLS program database. This database shall be updated as specified in the Regional program (but at least every five years) and shall include sufficient information to model the UFLS program in dynamic simulations of the interconnected transmission systems.

d. Technical assessment and documentation of the effectiveness of the design and implementation of the Regional UFLS program. This technical assessment shall be conducted periodically and shall (at least every five years or as required by changes in system conditions) include, but not be limited to:

1. A review of the frequency set points and timing, and
2. Dynamic simulation of possible disturbance that cause the Region or portions of the Region to experience the largest imbalance between demand (load) and generation.

e. Determination, as appropriate, of maintenance, testing, and calibration requirements by member systems.

Documentation of each Region's UFLS program and its database information shall be current and provided to NERC on request (within 30 days).

Documentation of the current technical assessment of the UFLS program shall also be provided to NERC on request (within 30 days). (S1)

M2. Those entities owning or operating an UFLS program shall ensure that their programs are consistent with Regional UFLS program requirements as specified in Measurement M1. Such entities shall provide and annually update their UFLS data as necessary for the Region to maintain and update and UFLS program as specified in Measurement M1. The documentation of an entity's UFLS program shall be provided to the Region on request (within 30 days). (S1)

M3. UFLS equipment owners shall have an UFLS equipment maintenance and testing program in place. This program shall include UFLS equipment identification, the schedule for UFLS equipment testing, and the schedule for UFLS equipment maintenance. These programs shall be maintained and documented, and the results of implementation shall be provided to the Regions and NERC on request (within 30 days).

M4. Those entities owning or operating UFLS programs shall analyze and document their UFLS program performance in accordance with Standard III.D. S1-S2, M1, including the performance of UFLS equipment and program effectiveness following system events resulting in system frequency excursions below the initializing set points of the UFLS program. The analysis shall include, but not be limited to:

1. A description of the event including initiating conditions
2. A review of the UFLS set points and tripping times
3. A simulation of the event
4. A summary of the findings

Documentation of the analysis shall be provided to the Regions and NERC on request 90 days after the system event.

Guides

G1. The UFLS programs should occur in steps related to frequency or rate of frequency decay as determined from system simulation studies. These studies are critical to coordinate the amount of load shedding necessary to arrest frequency decay, minimize loss of load, and permit timely system restoration.

G2. The UFLS programs should be coordinated with generation protection and control, undervoltage and other load shedding programs, Regional load restoration programs, and transmission protection and control.

G3. The technical assessment of UFLS programs should include reviews of system design and dynamic simulations of disturbances that would cause the largest expected imbalances between customer demand and generation. Both peak and off-peak system demand levels should be considered. The assessments should predict voltage and power transients at a widespread number of locations as well as the rate of frequency decline, and should reflect the operation of underfrequency sensing devices. Potential system separation points and resulting system islands should be determined.

G4. Except for qualified automatic isolation plans, the opening of transmission interconnections by underfrequency relaying should be considered only after the coordinated load shedding program has failed to arrest system frequency decline and intolerable system conditions exist.

G5. A generation-deficient entity may establish an automatic islanding plan in lieu of automatic load shedding, if by doing so it removes the burden it has imposed on the transmission systems. This islanding plan may be used only if it complies with the Regional UFLS program and leaves the remaining interconnected bulk electric systems intact, in demand and generation balance, and with no unacceptable high voltages.

G6. In cases where area isolation with a large surplus of generation compared to demand can be anticipated, automatic generator tripping or other remedial measures should be considered to prevent excessive high frequency and resultant uncontrolled generator tripping and equipment damage.

G7. UFLS relay settings and the underfrequency protection of generating units as well as any other manual or automatic actions that can be expected to occur under conditions of frequency decline should be coordinated.

G8. The UFLS program should be separate, to the extent possible, from manual load shedding schemes such that the same loads are not shed by both schemes.

G9. Generator underfrequency protection should not operate until the UFLS programs have operated and failed to maintain the system frequency at an operable level. This sequence of operation is necessary both to limit the amount of load shedding required and to help the systems avoid a complete collapse. Where this sequence is not possible, UFLS programs should consider and compensate for any generator whose underfrequency protection is required to operate before a portion of the UFLS program.

G10. Plans to shed load automatically should be examined to determine if unacceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated. If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided. If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability. If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

G11. Where the UFLS program fails to arrest frequency decline, generators may be isolated with local load to minimize loss of generation and enable timely system restoration.

E. Undervoltage Load Shedding

Introduction

Electric systems that experience heavy loadings on transmission facilities with limited reactive power control can be vulnerable to voltage instability. Such instability can cause tripping of generators and transmission facilities resulting in loss of customer demand as well as system collapse. Since voltage collapse can occur suddenly, there may not be sufficient time for operator actions to stabilize the systems. Therefore, a load shedding scheme that is automatically activated as a result of undervoltage conditions in portions of a system can be an effective means to stabilize the interconnected systems and mitigate the effects of a voltage collapse. It is imperative that undervoltage relays be coordinated with other system protection and control devices used to interrupt electric supply to customers.

Standards

S1. Automatic undervoltage load shedding (UVLS) programs shall be planned and implemented in coordination with other UVLS programs in the Region and, where appropriate, with neighboring Regions.

S2. All UVLS programs shall be coordinated with generation control and protection systems, underfrequency load shedding programs, Regional load restoration programs, and transmission protection and control programs.

Measurements

M1. Those entities owning or operating UVLS programs shall coordinate and document their UVLS programs including descriptions of the following:
a. Coordination of UVLS programs within the subregions, the Region, and, where appropriate, among Regions.
b. Coordination of UVLS programs with generation protection and control, UFLS programs, Regional load restoration programs, and transmission protection and control programs.
c. Design details including size of customer demand (load) blocks (% of connected load), corresponding voltage set points, relay and breaker operating times, intentional delays, related generation protection, islanding schemes, automatic load restoration schemes, or any other schemes that are part of or impact the UVLS programs.
Documentation of the UVLS programs shall be provided to the appropriate Regions and NERC on request. (S1, S2)

M2. Those entities owning or operating UVLS programs shall ensure that their programs are consistent with any Regional UVLS programs and that exist including automatically shedding load in the amounts and at locations, voltages, rates, and times consistent with any Regional requirements. (S1)

M3. Each Region shall maintain and annually update an UVLS program database. This database shall include sufficient information to model the UVLS program in dynamic simulations of the interconnected transmission systems. (S1)

M4. Those entities owning or operating UVLS programs shall periodically (at least every five years or as required by changes in system conditions) conduct and document a technical assessment of the effectiveness of the design and implementation of its UVLS program. Documentation of the UVLS technical assessment shall be provided to the appropriate Regions and NERC on request. (S1)

M5. Those entities owning or operating UVLS programs shall have a maintenance program to test and calibrate their UVLS relays to ensure accuracy and reliable operation. Documentation of the implementation of the maintenance program shall be provided to the appropriate Regions and NERC on request. (S1)

M6. Those entities owning or operating an UVLS program shall analyze and document all system undervoltage events below the initiating set points of their UVLS programs. Documentation of the analysis shall be provided to the appropriate Regions and NERC on request. (S1)

Guides

G1. UVLS programs should be coordinated with other system protection and control programs (e.g., timing of line reclosing, tap changing, overexcitation limiting, capacitor bank switching, and other automatic switching schemes). G2. Automatic UVLS programs should be coordinated with manual load shedding programs.

G3. Manual load shedding programs should not include, to the extent possible, customer demand that is part of an automatic UVLS program.

G4. Assessments of UVLS programs should include system dynamic simulations that represent generator overexcitation limiters, load restoration dynamics (tap changing, motor dynamics), and shunt compensation switching.

G5. Plans to shed load automatically should be examined to determine if acceptable overfrequency, overvoltage, or transmission overloads might result. Potential unacceptable conditions should be mitigated. If overfrequency is likely, the amount of load shed should be reduced or automatic overfrequency load restoration should be provided. If overvoltages are likely, the load shedding program should be modified (e.g., change the geographic distribution) or mitigation measures (e.g., coordinated tripping of shunt capacitors or reactors) should be implemented to minimize that probability. If transmission capabilities will likely be exceeded, the underfrequency relay settings (e.g., location, trip frequency, or time delay) should be altered or other actions taken to maintain transmission loadings within capabilities.

F. Special Protection Systems

Introduction

A special protection system (SPS) or remedial action scheme (RAS) is designed to detect abnormal system conditions and take pre-planned, corrective action (other than the isolation of faulted elements) to provide acceptable system performance. SPS actions, include among others, changes in demand (e.g., load shedding), generation, or system configuration to maintain system stability, acceptable voltages, or acceptable facility loadings.

The use of an SPS is an acceptable practice to meet the system performance requirements as defined under Categories A, B, or C of Table I of the I.A. Standards on Transmission Systems. Electric systems that rely on an SPS to meet the performance levels specified by the **NERC Planning Standards** must ensure that the SPS is highly reliable.

Examples of SPS misoperation include, but are not limited to, the following:

1. The SPS does not operate as intended.
2. The SPS fails to operate when required.
3. The SPS operates when not required.

Standards

S1. An SPS shall be designed so that a single SPS component failure, when the SPS was intended to operate, does not prevent the interconnected transmission system from meeting the performance requirements defined under Categories A, B, or C of Table 1 of the I.A Standards on Transmission Systems.

S2. The inadvertent operation of an SPS shall meet the same performance requirement (Category A, B, or C of Table I of the I.A. Standards on Transmission Systems) as that required of the contingency for which it was designed, and shall not exceed Category C.

S3. SPS installations shall be coordinated with other protection and control systems.

S4. All SPS misoperations shall be analyzed for cause and corrective action.

S5. SPS maintenance and testing programs shall be developed and implemented.

Measurements

M1. Each Region whose members use or are planning to use an SPS shall have a documented Regional review procedure to ensure the SPS complies with Regional

criteria and guides and **NERC Planning Standards**. The Regional review procedure shall include:
1. Description of the process for submitting a proposed SPS for Regional review.
2. Requirements to provide data that describes design, operation, and modeling of an SPS.
3. Requirements to demonstrate that the SPS design will meet above SPS Standards S1 and S2.
4. Requirements to demonstrate the proposed SPS will coordinate with other protection and control systems and applicable Regional emergency procedures.
5. Regional definition of misoperation.
6. Requirements for analysis and documentation of corrective action plans for all SPS misoperations.
7. Identification of the Regional group responsible for the Region's review procedure and the process for Regional approval of the procedure.
8. Determination, as appropriate, of maintenance and testing requirements.

Documentation of the Regional SPS review procedure shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3, S4)

M2. A Region that has a member with an SPS installed shall maintain an SPS database. The database shall include the following types of information:
1. Design Objectives – Contingencies and system conditions for which the SPS was designed,
2. Operation – The actions taken by the SPS in response to disturbance conditions, and
3. Modeling – Information on detection logic or relay settings that control operation of the SPS.
Documentation of the Regional database or the information therein shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M3. A Region shall assess the operation, coordination, and effectiveness of all SPSs installed in the Region at least once every five years for compliance with NERC Planning Standards and Regional criteria. The Regions shall provide either a summary report or a detailed report of this assessment to affected Regions or NERC, on request (within 30 days). The documentation of the Regional SPS assessment shall include the following elements:
1. Identification of group conducting the assessment and the date the assessment was performed.
2. Study years, system conditions, and contingencies analyzed in the technical studies on which the assessment is based and when those technical studies were performed.
3. Identification of SPSs that were found not to comply with NERC Planning Standards and Regional criteria.
4. Discussion of any coordination problems found between an SPS and other protection and control systems.
5. Provide corrective action plans for non-compliant SPSs. (S1, S2, S3)

M4. SPS owners shall maintain a list of and provide data for existing and proposed SPSs as defined in Measurement III.F. S1-S3, M2. New or functionally modified SPSs shall be reviewed in accordance with the Regional procedures as defined in Measurement III.F. S1-S4, M1 prior to being placed in service. Documentation of SPS data and the results of studies that show compliance of new or functionally modified SPSs with NERC Planning Standards and Regional criteria shall be provided to affected Regions and NERC, on request (within 30 days). (S1, S2, S3)

M5. SPS owners shall analyze SPS operations and maintain a record of all misoperations in accordance with Regional procedures in Measurement III.F. S1-S4, M1. Corrective actions shall be taken to avoid future misoperations. Documentation of the misoperation analyses and the corrective action plans shall be provided to the affected Regions and NERC, on request (within 90 days). (S4)

M6. SPS owners shall have an SPS maintenance and testing program in place. This program shall include the SPS identification, summary of test procedures, frequency of testing, and frequency of maintenance. Documentation of the program and its implementation shall be provided to the appropriate Regions and NERC on request (within 30 days). (S5)

Guides

G1. Complete redundancy should be considered in the design of an SPS with diagnostic and self-check features to detect and alarm when essential components fail or critical functions are not operational.

G2. No identifiable common mode events should result in the coincident failure of two or more SPS components.

G3. An SPS should be designed to operate only for conditions that require specific protective or control actions.

G4. As system conditions change, an SPS should be disarmed to the extent that its use is unnecessary.

G5. SPSs should be designed to minimize the likelihood of personnel error, such as incorrect operation and inadvertent disabling. Test devices or switches should be used to eliminate the necessity for removing or disconnecting wires during testing.

G6. The design of SPSs both in terms of circuitry and physical arrangement should facilitate periodic testing and maintenance. Test facilities and test procedures should be designed such that they do not compromise the independence of redundant SPS groups.

G7. SPSs that rely on circuit breakers to accomplish corrective actions should as a minimum use separate trip coils and separately fused dc control voltages.