

THE INTERTIE MANAGEMENT COMMITTEES' RAILBELT OPERATING AND RELIABILITY STANDARDS

Updated October 10th, 2017

Introduction

Shortly after the interconnection of the Railbelt Northern and Southern systems in 1985, the newly formed Intertie Operating Committee (IOC) reviewed, modified, and adopted the North American Electric Reliability Council's "Operating Guides for Interconnected Power Systems." In 1992, these Operating Guides were subsumed into the Alaska Systems Coordinating Council's "Operating and Planning Guides." In each case the planning and operating guides for the large heavily interconnected systems of the Lower 48, Canada, and Mexico required significant revision for application in the relatively small and lightly interconnected Railbelt Electric System. In the intervening years a number of changes ensued in the electric power systems of North America and, in 2005, the Railbelt Utility Group Managers (RUG) directed their respective operating managers to form an ad-hoc reliability committee tasked with reviewing the most recent version of the North American Electric Reliability Corporation's (NERC) "Reliability Standards for the Bulk Electric Systems of North America" and further with modifying them and updating the Railbelt's planning and operating standards.

The "Ad-Hoc Railbelt Reliability Committee (RRC)", as it was called, working with the State of Alaska's "Alaska Energy Authority" (AEA) formed committee working rules and open public process for the standards review. Over the following several years the RRC reviewed some 650 pages of NERC standards. Drawing on this body of knowledge and on the existing Railbelt operation and planning standards as well as current Railbelt practices selectively modified and updated the NERC standards. The following standards represent the output of this process.

The group, the RRC has drafted these standards giving careful consideration to the many technical and operational issues involved with interconnecting entities to the Alaska Railbelt Electrical System (also referred to as the "Railbelt Interconnection", "the "Railbelt Grid" or "The System") and with five overarching goals:

- *First, these standards set the minimum requirements for interconnection to The System; the local entity at the point of interconnection may have additional or more stringent interconnection standards.*
- *Second, to the extent practical, these interconnection standards should be performance based rather than requirements based.*
- *Third, to the extent practical, interconnecting entities should not be allowed to degrade the performance or reliability of The System. Such degradation in performance shall be determined by modeling the Railbelt Electrical System using the boundary dispatch cases against all category B and probable category C contingencies.*
- *Fourth, interconnecting entities should not be required to build or improve System facilities beyond those necessary to meet the third overarching goal (above).*
- *Fifth, the interconnecting entity, as a condition of interconnection, shall abide by this and all other applicable Railbelt standards as they may be modified or implemented from time to time. A Balancing Authority having jurisdiction shall ascertain that the new entity agrees to these standards prior to interconnection or that another entity will absorb the new entity's obligations as additional obligations to their own. The new entity may have additional obligations imposed by the local Transmission Owner.*

Given the complex and technical nature of the subject, the authors have worked diligently to maintain a high level of clarity throughout this document, in order to meet the needs of the participants, but they recognize that these standards are often based upon highly technical subject matter. To aid in this understanding a glossary of terms used in Railbelt reliability has been developed and included. If terms used in these standards are not defined in the attached glossary the reader should look to:

- The specific contractual glossaries found in Railbelt agreements related to the subject under consideration i.e., the Bradley Lake Agreements and The Alaska Intertie agreement as amended.
- The Railbelt Glossary of Terms, modified from the “Glossary of Terms Used in NERC Reliability Standards”

Further, to aid in understanding and implementing these requirements and criteria, the Intertie Management Committee (IMC) will require potential entities, where necessary, to obtain the assistance of qualified engineering professionals with specific expertise in the areas of electrical supply systems, power system analysis, protection, as well as control. Such professionals must have demonstrated experience in modeling, designing, constructing, commissioning and operating facilities on small, stability-limited interconnections.

These guidelines are subject to revision, at any time, at the discretion of the IMC. This document is not intended to be a design specification.

The essential documents are organized as follows:

The first set of standards defines how entities must plan for and operate in a reliable electric system. These standards draw heavily on the work of NERC, but have been modified in many cases to recognize the lean nature of the Railbelt System, it’s relatively light loading and stability limited nature.

The AKBAL’s and AKVAR’s are the standards dealing with how balancing authorities (most of the Alaskan utilities are vertically integrated and are each their own balancing authority) work with each other. It is these standards that establish a requirement for reserve policies.

The AKFAC’s are the standards dealing with new construction, maintenance and ratings. These standards contain the requirements for interconnection standards. It should be noted that these interconnection standards are minimums Railbelt wide and that more stringent interconnection requirements may be imposed at the local level by the local entity.

The AKINT’s are the standards dealing with interchange scheduling.

The AKRES standard contains the reserves design of the Railbelt Grid. This standard draws heavily upon Exhibit H of the Amended and Restated Alaska Intertie Agreement. This standard sets the requirements for the resource adequacy, operating reserves, spinning reserves, and regulating reserves. Balancing Authorities with small units (less than 10 MW) but with non-dispatchable fuel sources may find that they have little to no spin obligation, but will likely have a large regulating obligation.

The AKTPLs are the standards dealing with contingency categorization and reporting under normal and Emergency conditions.

These standards are applicable to entities/equipment, ***where a single contingency (Category B) could result in the net change of 10 or more MW's of generating capacity or load. This limit is based on our current system bias where loss of a 10 MW unit will cause the system frequency to drop 0.1 Hz.*** In most of our control centers, this is the level where the first level of frequency alarms are initiated indicating a major system disturbance. As with other standards, the IMC may modify this limit as the Railbelt System changes over time. Finally, the Railbelt Glossary of Terms defines terms specific to these standards.

While not specifically addressed in the standards, a prolonged interruption of the fuel supply to a generating plant is an unlikely but highly disruptive contingency. Such an event would likely be coincident to a loss of heating fuel as well and if occurring in the winter could be extremely disruptive and have significant life safety consequences.

It is required that each generating entity have contingency plans for loss of the primary fuel supply. This may include but not be limited to use of alternate fuels, generation at alternate locations or Emergency power purchase agreements with other generators.

Further, a significant attack on or interruption to critical Cyber-Assets could potentially cause wide spread System disruptions. To the extent practical systems of this nature must be adequately "fire-walled" or physically isolated from outside intrusion.

The IMC is currently working on Critical Infrastructure Protection Standards to address these issues. They will be incorporated into the standards as soon as practical.

These Railbelt standards supersede the previous reliability criteria found in the ASCC documents "ASCC Operating Guides for Interconnected Utilities and Alaska Intertie Operating Guides" and the "ASCC Planning Criteria for the reliability of interconnected electric utilities." Where this document is silent, the ASCC documents should continue to be referenced.

Sanctions for Levels of Non-Compliance when not otherwise described in the standards refer to the Sanctions Matrix for Non-Compliance. The IMC is authorized to change the sanctions as the needs may arise, but only for future infractions.

All entities interconnected to the Railbelt System must fill out an Entity Function Matrix (Exhibit A) checking off the functions which they believe they will perform. The IMC will review and modify this as required and the document will be used to determine an entity's obligations as well as what areas it may participate in. Vertically integrated utilities may find themselves participating in most, if not all categories.

Unless addressed specifically in the standards, records will be kept a minimum of 5 years or if they are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved.

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Alaska Railbelt Standard AKBAL-001-1 — Real Power Balancing Control Performance

A. Introduction

1. **Title:** Real Power Balancing Control Performance

2. **Number:** AKBAL-001-1

3. **Purpose:**

To maintain Interconnection steady-state frequency within defined limits by balancing real power demand and supply in real-time.

4. **Applicability:**

4.1. Balancing Authorities

5. **Effective Date:** 4 months from package adoption

B. Requirements

R1. Each Balancing Authority shall operate such that, on a rolling 12-month basis, the average of the clock-minute averages of the Balancing Authority's Area Control Error (ACE) divided by 10B (B is the clock-minute average of the Balancing Authority Area's Frequency Bias) times the corresponding clock-minute averages of the Interconnection's Frequency Error is less than a specific limit. This limit ϵ_1^2 is a constant derived from a targeted frequency bound (separately calculated for each Interconnection) that is reviewed and set as necessary by the IMC.

$$AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right] \leq \epsilon_1^2 \text{ or } \frac{AVG_{Period} \left[\left(\frac{ACE_i}{-10B_i} \right)_1 * \Delta F_1 \right]}{\epsilon_1^2} \leq 1$$

The equation for ACE is:

$$ACE = (NI_A - NI_S) - 10B (F_A - F_S) - I_{ME}$$

where:

- NI_A is the algebraic sum of actual flows on all tie lines.
- NI_S is the algebraic sum of scheduled flows on all tie lines.
- B is the Frequency Bias Setting (MW/0.1 Hz) for the Balancing Authority. The constant factor 10 converts the frequency setting to MW/Hz.
- F_A is the actual frequency.
- F_S is the scheduled frequency. F_S is normally 60 Hz but may be offset to effect manual time error corrections.
- I_{ME} is the meter error correction factor typically estimated from the difference between the integrated hourly average of the net tie line flows (NI_A) and the hourly net interchange demand measurement (megawatt-hour). This term should normally be very small or zero.

- R2.** Each Balancing Authority shall operate such that its average ACE for at least 90% of clock-ten-minute periods (6 non-overlapping periods per hour) during a calendar month is within a specific limit, referred to as L_{10} .

$$AVG_{10\text{-minute}}(ACE_i) \leq L_{10}$$

where:

$$L_{10} = 1.65 \epsilon_{10} \sqrt{(-10B_i)(-10B_s)}$$

- R2.1.** ϵ_{10} is a constant derived from the targeted frequency bound. It is the targeted root-mean-square (RMS) value of ten-minute average Frequency Error based on frequency performance over a given year. The bound, ϵ_{10} , is the same for every Balancing Authority Area within an Interconnection, and B_s is the sum of the Frequency Bias Settings of the Balancing Authority Areas in the respective Interconnection. For Balancing Authority Areas with variable bias, this is equal to the sum of the minimum Frequency Bias Settings.
- R2.2.** Each Balancing Authority providing Overlap Regulation Service shall evaluate Requirement R1 (i.e., Control Performance Standard 1 or CPS1) and Requirement R2 (i.e., Control Performance Standard 2 or CPS2) using the characteristics of the combined ACE and combined Frequency Bias Settings.
- R2.3.** Any Balancing Authority receiving Overlap Regulation Service shall not have its control performance evaluated (i.e. from a control performance perspective, the Balancing Authority has shifted all control requirements to the Balancing Authority providing Overlap Regulation Service).

C. Measures

- M1.** Each Balancing Authority shall achieve, as a minimum, Requirement 1 (CPS1) compliance of 100%.

CPS1 is calculated by converting a compliance ratio to a compliance percentage as follows:

$$CPS1 = (2 - CF) * 100\%$$

The frequency-related compliance factor, CF, is a ratio of all one-minute compliance parameters accumulated over 12 months divided by the target frequency bound:

$$CF = \frac{CF_{12\text{-month}}}{(\epsilon_1)^2}$$

Where:

ϵ_1 is defined in Requirement R1.

The rating index $CF_{12\text{-month}}$ is derived from 12 months of data. The basic unit of data comes from one-minute averages of ACE, Frequency Error and Frequency Bias Settings.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

A clock-minute average is the average of the reporting Balancing Authority's valid measured variable (i.e., for ACE and for Frequency Error) for each sampling cycle during a given clock-minute.

$$\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} = \frac{\left(\frac{\sum ACE_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}} \right)}{-10B}$$

$$\Delta F_{\text{clock-minute}} = \frac{\sum \Delta F_{\text{sampling cycles in clock-minute}}}{n_{\text{sampling cycles in clock-minute}}}$$

The Balancing Authority's clock-minute compliance factor (CF) becomes:

$$CF_{\text{clock-minute}} = \left[\left(\frac{ACE}{-10B} \right)_{\text{clock-minute}} * \Delta F_{\text{clock-minute}} \right]$$

Normally, sixty (60) clock-minute averages of the reporting Balancing Authority's ACE and of the respective Interconnection's Frequency Error will be used to compute the respective hourly average compliance parameter.

$$CF_{\text{clock-hour}} = \frac{\sum CF_{\text{clock-minute}}}{n_{\text{clock-minute samples in hour}}}$$

The reporting Balancing Authority shall be able to recalculate and store each of the respective clock-hour averages (CF clock-hour average-month) as well as the respective number of samples for each of the twenty-four (24) hours (one for each clock-hour, i.e., hour-ending (HE) 0100, HE 0200, ..., HE 2400).

$$CF_{\text{clock-hour average-month}} = \frac{\sum_{\text{days-in-month}} [(CF_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum_{\text{days-in-month}} [n_{\text{one-minute samples in clock-hour}}]}$$

$$CF_{\text{month}} = \frac{\sum_{\text{hours-in-day}} [(CF_{\text{clock-hour average-month}})(n_{\text{one-minute samples in clock-hour averages}})]}{\sum_{\text{hours-in day}} [n_{\text{one-minute samples in clock-hour averages}}]}$$

The 12-month compliance factor becomes:

$$CF_{12\text{-month}} = \frac{\sum_{i=1}^{12} (CF_{\text{month-}i})(n_{(\text{one-minute samples in month})-i})}{\sum_{i=1}^{12} [n_{(\text{one-minute samples in month})-i}]}$$

In order to ensure that the average ACE and Frequency Deviation calculated for any one-minute interval is representative of that one-minute interval, it is necessary that at least 50% of both ACE and Frequency Deviation samples during that one-minute interval be present. Should a sustained interruption in the recording of ACE or Frequency Deviation due to loss of telemetering or computer unavailability result in a one-minute interval not containing at least 50% of samples of both ACE and Frequency Deviation, that one-minute interval shall be excluded from the calculation of CPS1.

- M2.** Each Balancing Authority shall achieve, as a minimum, Requirement R2 (CPS2) compliance of 90%. CPS2 relates to a bound on the ten-minute average of ACE. A compliance percentage is calculated as follows:

$$CPS2 = \left[1 - \frac{\text{Violations}_{\text{month}}}{(\text{Total Periods}_{\text{month}} - \text{Unavailability Periods}_{\text{month}})} \right] * 100$$

The violations per month are a count of the number of periods that ACE clock-ten-minutes exceeded L_{10} . ACE clock-ten-minutes is the sum of valid ACE samples within a clock-ten-minute period divided by the number of valid samples.

Violation clock-ten-minutes

$$= 0 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| \leq L_{10}$$

$$= 1 \text{ if } \left| \frac{\sum ACE}{n_{\text{samples in 10-minutes}}} \right| > L_{10}$$

Each Balancing Authority shall report the total number of violations and unavailable periods for the month. L_{10} is defined in Requirement R2.

Since CPS2 requires that ACE be averaged over a discrete time period, the same factors that limit total periods per month will limit violations per month. The calculation of total periods per month and violations per month, therefore, must be discussed jointly.

A condition may arise which may impact the normal calculation of total periods per month and violations per month. This condition is a sustained interruption in the recording of ACE.

In order to ensure that the average ACE calculated for any ten-minute interval is representative of that ten-minute interval, it is necessary that at least half the ACE data samples are present for that interval. Should half or more of the ACE data be unavailable due to loss of telemetering or computer unavailability, that ten-minute interval shall be omitted from the calculation of CPS2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization.

Compliance Monitoring Period and Reset Timeframe

One calendar month.

1.3. Data Retention

The data that supports the calculation of CPS1 and CPS2 (Attachment 1-AKBAL-001-0) are to be retained in electronic form for at least a one-year period. If the CPS1 and CPS2 data for a Balancing Authority Area are undergoing a review to address a question that has been raised regarding the data, the data are to be saved beyond the normal retention period until the question is formally resolved. Each Balancing Authority shall retain for a rolling 12-month period the values of: one-minute average ACE (ACE_i), one-minute average Frequency Error, and, if using variable bias, one-minute average Frequency Bias.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance – CPS1

2.1. **Level 1:** The Balancing Authority Area's value of CPS1 is less than 100% but greater than or equal to 95%.

2.2. **Level 2:** The Balancing Authority Area's value of CPS1 is less than 95% but greater than or equal to 90%.

2.3. **Level 3:** The Balancing Authority Area's value of CPS1 is less than 90% but greater than or equal to 85%.

2.4. **Level 4:** The Balancing Authority Area's value of CPS1 is less than 85%.

3. Levels of Non-Compliance – CPS2

3.1. **Level 1:** The Balancing Authority Area's value of CPS2 is less than 90% but greater than or equal to 85%.

3.2. **Level 2:** The Balancing Authority Area's value of CPS2 is less than 85% but greater than or equal to 80%.

3.3. **Level 3:** The Balancing Authority Area's value of CPS2 is less than 80% but greater than or equal to 75%.

3.4. **Level 4:** The Balancing Authority Area's value of CPS2 is less than 75%.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	June 7, 2013	Original	New
1	May 2, 2016	Remove capacity/reserve graph	Modify

Attachment 1-AKBAL-001-1 CPS1 and CPS2 Data

CPS1 DATA	Description	Retention Requirements
ε_1	A constant derived from the targeted frequency bound. This number is the same for each Balancing Authority Area in the Interconnection.	Retain the value of ε_1 used in CPS1 calculation.
ACE_i	The clock-minute average of ACE.	Retain the 1-minute average values of ACE (525,600 values).
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value(s) of B_i used in the CPS1 calculation.
F_A	The actual measured frequency.	Retain the 1-minute average frequency values (525,600 values).
F_S	Scheduled frequency for the Interconnection.	Retain the 1-minute average frequency values (525,600 values).

CPS2 DATA	Description	Retention Requirements
V	Number of incidents per hour in which the absolute value of ACE clock-ten-minutes is greater than L_{10} .	Retain the values of V used in CPS2 calculation.
ε_{10}	A constant derived from the frequency bound. It is the same for each Balancing Authority Area within an Interconnection.	Retain the value of ε_{10} used in CPS2 calculation.
B_i	The Frequency Bias of the Balancing Authority Area.	Retain the value of B_i used in the CPS2 calculation.
B_s	The sum of Frequency Bias of the Balancing Authority Areas in the respective Interconnection. For systems with variable bias, this is equal to the sum of the minimum Frequency Bias Setting.	Retain the value of B_s used in the CPS2 calculation. Retain the 1-minute minimum bias value (525,600 values).
U	Number of unavailable ten-minute periods per hour used in calculating CPS2.	Retain the number of 10-minute unavailable periods used in calculating CPS2 for the reporting period.

Alaska Railbelt Standard AKBAL-002-1 — Disturbance Control Performance

A. Introduction

1. Title: Disturbance Control Performance

2. Number: AKBAL-002-1

3. Purpose:

The purpose of the Disturbance Control Standard (DCS) is to ensure the Balancing Authority is able to utilize its Contingency Reserve to balance resources and demand and return Interconnection frequency within defined limits following a Reportable Disturbance. Because generator failures are far more common than significant losses of load and because Contingency Reserve activation does not typically apply to the loss of load, the application of DCS is limited to the loss of supply and does not apply to the loss of load.

4. Applicability:

4.1. Balancing Authorities

4.2. Reserve Sharing Groups (Balancing Authorities may meet the requirements of AKBAL-002-1 through participation in a Reserve Sharing Group.)

4.3. IMC or, if formed by Utilities, a Regional Reliability Organization

5. Effective Date: 4 months from package adoption

B. Requirements

R1. Each Balancing Authority shall have access to and/or operate Contingency Reserve to respond to Disturbances. Contingency Reserve may be supplied from generation, energy storage systems, load shed, controllable load resources, other devices, or coordinated adjustments to Interchange Schedules.

R1.1. A Balancing Authority may elect to fulfill its Contingency Reserve obligations by participating as a member of a Reserve Sharing Group. In such cases, the Reserve Sharing Group shall have the same responsibilities and obligations as each Balancing Authority with respect to monitoring and meeting the requirements of Standard AKBAL-002-1.

R2. Each IMC member, Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group shall specify its Contingency Reserve policies, including:

R2.1. The minimum reserve requirement for the group, as determined by coordinated Railbelt under frequency load shed/spinning reserve/droop coordination study.

R2.2. Its allocation among members, as defined in the Reserve Policy, and as modified by coordinated Railbelt under frequency load shed/spinning reserve/droop coordination studies.

R2.3. The permissible mix of Operating Reserve – Spinning and Operating Reserve – Supplemental that may be included in Contingency Reserve.

R2.4. The procedure for applying Contingency Reserve in practice including recommendations on geographic dispersion.

R2.5. The limitations, if any, upon the amount of interruptible load that may be included.

- R2.6.** The same portion of resource capacity (e.g. reserves from jointly owned generation) shall not be counted more than once as Contingency Reserve by multiple Balancing Authorities.
- R3.** Each Balancing Authority or Reserve Sharing Group shall activate sufficient Contingency Reserve to comply with the DCS.
- R3.1.** As a minimum, the Balancing Authority or Reserve Sharing Group shall carry at least enough Contingency Reserve to cover the most severe single contingency. All Balancing Authorities and Reserve Sharing Groups shall review, no less frequently than annually, their probable contingencies to determine their prospective most severe single contingencies.
- R4.** A Balancing Authority or Reserve Sharing Group shall meet the Disturbance Recovery Criterion within the Disturbance Recovery Period for 100% of Reportable Disturbances. The Disturbance Recovery Criterion is:
- R4.1.** A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
- R4.2.** The default Disturbance Recovery Period is 10 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the IMC.
- R5.** Each Reserve Sharing Group shall comply with the DCS. A Reserve Sharing Group shall be considered in a Reportable Disturbance condition whenever a group member has experienced a Reportable Disturbance and calls for the activation of Contingency Reserves from one or more other group members. (If a group member has experienced a Reportable Disturbance but does not call for reserve activation from other members of the Reserve Sharing Group, then that member shall report as a single Balancing Authority.) Compliance may be demonstrated by either of the following two methods:
- R5.1.** The Reserve Sharing Group reviews group ACE (or equivalent) and demonstrates compliance to the DCS. To be in compliance, the group ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
- or
- R5.2.** The Reserve Sharing Group reviews each member's ACE in response to the activation of reserves. To be in compliance, a member's ACE (or its equivalent) must meet the Disturbance Recovery Criterion after the schedule change(s) related to reserve sharing have been fully implemented, and within the Disturbance Recovery Period.
- R6.** A Balancing Authority or Reserve Sharing Group shall fully restore its Contingency Reserves within the Contingency Reserve Restoration Period for its Interconnection.
- R6.1.** The Contingency Reserve Restoration Period begins at the end of the Disturbance Recovery Period.

R6.2. The default Contingency Reserve Restoration Period is 50 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the IMC.

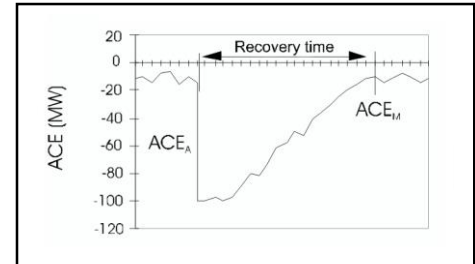
C. Measures

M1. A Balancing Authority or Reserve Sharing Group shall calculate and report compliance with the Disturbance Control Standard for all Disturbances involving all generating unit trips, transmission line trips, and distribution level disturbances that result in frequency deviation >.2 Hz. Regions may, at their discretion, require a lower reporting threshold. Disturbance Control Standard is measured as the percentage recovery (R_i).

For loss of generation:

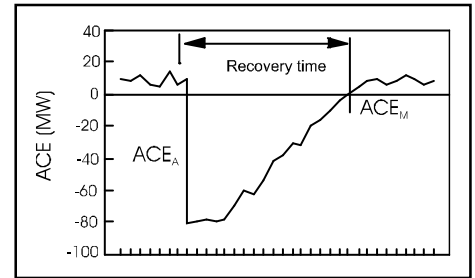
if $ACE_A < 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, ACE_A - ACE_M)}{MW_{Loss}} * 100\%$$



if $ACE_A \geq 0$
then

$$R_i = \frac{MW_{Loss} - \max(0, -ACE_M)}{MW_{Loss}} * 100\%$$



where:

- MW_{LOSS} is the MW size of the Disturbance as measured at the beginning of the loss,
- ACE_A is the pre-disturbance ACE,
- ACE_M is the maximum algebraic value of ACE measured within the ten minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{10 \text{ min}}$, and

The Balancing Authority or Reserve Sharing Group shall record the MW_{LOSS} value as measured at the site of the loss to the extent possible. The value should not be measured as a change in ACE since governor response and AGC response may introduce error.

The Balancing Authority or Reserve Sharing Group shall base the value for ACE_A on the average ACE over the period just prior to the start of the Disturbance (10 and 60 seconds prior and including at least 4 scans of ACE). In the illustration below, the horizontal line represents an averaging of ACE for 15 seconds prior to the start of the Disturbance with a result of $ACE_A = -25 \text{ MW}$.

only measures the recovery from sudden, unanticipated losses of supply-side resources.

Simultaneous Contingencies – Multiple Contingencies occurring within one minute or less of each other shall be treated as a single Contingency. If a multiple contingency event occurs within a time span greater than one minute the regional reliability organization will have at its discretion the option to consider it a single contingency. If the combined magnitude of the multiple Contingencies exceeds the most severe single Contingency, the loss shall be reported, but excluded from compliance evaluation.

Multiple Contingencies within the Reportable Disturbance Period – Additional Contingencies that occur after one minute of the start of a Reportable Disturbance but before the end of the Disturbance Recovery Period can be excluded from evaluation. The Balancing Authority or Reserve Sharing Group shall determine the DCS compliance of the initial Reportable Disturbance by performing a reasonable estimation of the response that would have occurred had the second and subsequent contingencies not occurred.

Multiple Contingencies within the Contingency Reserve Restoration Period - Additional Reportable Disturbances that occur after the end of the Disturbance Recovery Period but before the end of the Contingency Reserve Restoration Period shall be reported and included in the compliance evaluation. However, the Balancing Authority or Reserve Sharing Group can request a waiver from the Resources Subcommittee for the event if the contingency reserves were rendered inadequate by prior contingencies and a good faith effort to replace contingency reserve can be shown.

2. Levels of Non-Compliance

A representative from each Balancing Authority or Reserve Sharing Group that was non-compliant in the calendar quarter most recently completed shall provide written documentation verifying that the Balancing Authority or Reserve Sharing Group will apply the appropriate DCS performance adjustment beginning the first day of the succeeding month, and will continue to apply it for three months. The written documentation shall accompany the quarterly Disturbance Control Standard Report when a Balancing Authority or Reserve Sharing Group is non-compliant.

2.1. Level 1: Value of the average percent recovery for the quarter is less than 100% but greater than or equal to 95%.

2.2. Level 2: Value of the average percent recovery for the quarter is less than 95% but greater than or equal to 90%.

2.3. Level 3: Value of average percent recovery for the quarter is less than 90% but greater than or equal to 85%.

2.4. Level 4: Value of average percent recovery for the quarter is less than 85%.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2016	45 minute recovery	defined terms
2	October 20, 2016	Renamed the Reserve Policy	change

Alaska Railbelt Standard AKBAL-003-1 — Frequency Response and Bias

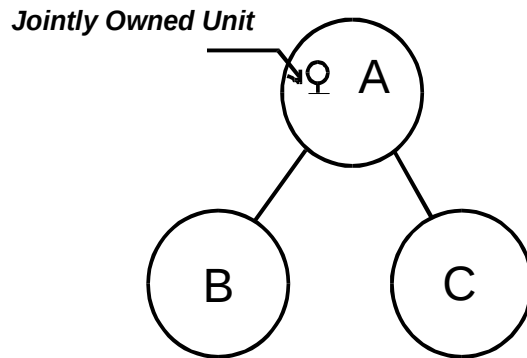
A. Introduction

- 1. Title: Frequency Response and Bias**
- 2. Number:** AKBAL-003-1
- 3. Purpose:**
This standard provides a consistent method for calculating the Frequency Bias component of ACE.
- 4. Applicability:**
 - 4.1.** Balancing Authorities
- 5. Effective Date:** 1 month from package adoption

B. Requirements

- R1.** Each Balancing Authority shall review its Frequency Bias Settings by January 1 of each year and recalculate its setting to reflect any change in the Frequency Response of the Balancing Authority Area.
 - R1.1.** The Balancing Authority may change its Frequency Bias Setting, and the method used to determine the setting, whenever any of the factors used to determine the current bias value change.
 - R1.2.** Each Balancing Authority shall report its Frequency Bias Setting, and method for determining that setting, to the IMC.
- R2.** Each Balancing Authority shall establish and maintain a Frequency Bias Setting that is as close as practical to, or greater than, the Balancing Authority's Frequency Response. Frequency Bias may be calculated several ways:
 - R2.1.** The Balancing Authority may use a fixed Frequency Bias value which is based on a fixed, straight-line function of Tie Line deviation versus Frequency Deviation. The Balancing Authority shall determine the fixed value by observing and averaging the Frequency Response for several Disturbances during on-peak hours.
 - R2.2.** The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such as load, generation, governor characteristics, and frequency.
- R3.** Each Balancing Authority shall operate its Automatic Generation Control (AGC) on Tie Line Frequency Bias, unless such operation is adverse to system or Interconnection reliability.
- R4.** Balancing Authorities that use Dynamic Scheduling or Pseudo-ties for jointly owned units shall reflect their respective share of the unit governor droop response in their respective Frequency Bias Setting.
 - R4.1.** Fixed schedules for jointly owned units mandate that Balancing Authority (A) that contains the Jointly Owned Unit must incorporate the respective share of the unit governor droop response for any Balancing Authorities that have fixed schedules (B and C). See the diagram below.

- R4.2.** The Balancing Authorities that have a fixed schedule (B and C) but do not contain the Jointly Owned Unit shall not include their share of the governor droop response in their Frequency Bias Setting.



- R5.** Balancing Authorities that serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of the Balancing Authority's estimated yearly peak demand per 0.1 Hz change.

- R5.1.** Balancing Authorities that do not serve native load shall have a monthly average Frequency Bias Setting that is at least 1% of its estimated maximum generation level in the coming year per 0.1 Hz change.

- R6.** A Balancing Authority that is performing Overlap Regulation Service shall increase its Frequency Bias Setting to match the frequency response of the entire area being controlled. A Balancing Authority shall not change its Frequency Bias Setting when performing Supplemental Regulation Service.

C. Measures

- M1.** Each Balancing Authority shall perform Frequency Response surveys when called for by the IMC to determine the Balancing Authority's response to Interconnection Frequency Deviations.

D. Compliance

1. Compliance Monitoring Process
2. IMC or, if formed by the Utilities, a Regional Reliability Organization.**Non-Compliance**

Level 1.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2016	no change in meaning	defined terms

Alaska Railbelt Standard AKBAL-004-1 — Time Error Correction

A. Introduction

1. Title: Time Error Correction

2. Number: AKBAL-004-1

3. Purpose:

The purpose of this standard is to ensure that Time Error Corrections are conducted in a manner that does not adversely affect the reliability of the Interconnection.

Although encouraged, there is no obligation for an electrical island to obtain the same time error as a neighboring island prior to synchronization.

4. Applicability:

4.1. Reliability Coordinators

4.2. Balancing Authorities

5. Effective Date: 1 month from package adoption

B. Requirements

R1. Only a Reliability Coordinator shall be eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection shall be designated by the IMC to serve as Interconnection Time Monitor.

R2. The Interconnection Time Monitor shall monitor Time Error and shall initiate or terminate corrective action orders in accordance with the Time Error Correction Procedure.

R3. Each Balancing Authority, when requested, shall participate in a Time Error Correction by one of the following methods:

R3.1. The Balancing Authority shall offset its frequency schedule by 0.02 Hertz, leaving the Frequency Bias Setting normal; or

R3.2. The Balancing Authority shall offset its Net Interchange Schedule (MW) by an amount equal to the computed bias contribution during a 0.02 Hertz Frequency Deviation (i.e. 20% of the Frequency Bias Setting).

R4. Any Reliability Coordinator in an Interconnection shall have the authority to request the Interconnection Time Monitor to terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations.

R4.1. Balancing Authorities that have reliability concerns with the execution of a Time Error Correction shall notify their Reliability Coordinator and request the termination of a Time Error Correction in progress.

C. Measures

Not specified.

D. Non-Compliance

Level 1

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	June 7, 2013	Original	New
1	May 2, 2016	No time zero prior to sync	Modify

Alaska Railbelt Standard AKBAL-005-1 — Automatic Generation Control

A. Introduction

1. Title: Automatic Generation Control

2. Number: AKBAL-005-1

3. Purpose:

This standard establishes requirements for Balancing Authority Automatic Generation Control (AGC) necessary to calculate Area Control Error (ACE) and to routinely deploy the Regulating Reserve. The standard also ensures that all facilities and load electrically synchronized to the Interconnection are included within the metered boundary of a Balancing Authority Area so that balancing of resources and demand can be achieved.

4. Applicability:

4.1. Balancing Authorities

4.2. Generator Operators

4.3. Transmission Operators

4.4. Load Serving Entities

5. Effective Date: 1 month from package adoption

B. Requirements

R1. All generation, transmission, and load operating within an Interconnection must be included within the metered boundaries of a Balancing Authority Area.

R1.1. Each Generator Operator with generation facilities operating in an Interconnection shall ensure that those generation facilities are included within the metered boundaries of a Balancing Authority Area.

R1.2. Each Transmission Operator with transmission facilities operating in an Interconnection shall ensure that those transmission facilities are included within the metered boundaries of a Balancing Authority Area.

R1.3. Each Load-Serving Entity with load operating in an Interconnection shall ensure that those loads are included within the metered boundaries of a Balancing Authority Area.

R2. Each Balancing Authority shall maintain Regulating Reserve that can be controlled by AGC to meet the Control Performance Standard.

R3. A Balancing Authority providing Regulation Service shall ensure that adequate metering, communications, and control equipment are employed to prevent such service from becoming a Burden on the Interconnection or other Balancing Authority Areas.

R4. A Balancing Authority providing Regulation Service shall notify the Host Balancing Authority for whom it is controlling if it is unable to provide the service, as well as any Intermediate Balancing Authorities.

R5. A Balancing Authority receiving Regulation Service shall ensure that backup plans are in place to provide replacement Regulation Service should the supplying Balancing Authority no longer be able to provide this service.

- R6.** The Balancing Authority's AGC shall compare total Net Actual Interchange to total Net Scheduled Interchange plus Frequency Bias obligation to determine the Balancing Authority's ACE. Single Balancing Authorities operating asynchronously may employ alternative ACE calculations such as (but not limited to) flat frequency control. If a Balancing Authority is unable to calculate ACE for more than 30 minutes, it shall notify its Reliability Coordinator.
- R7.** The Balancing Authority shall operate AGC continuously unless such operation adversely impacts the reliability of the Interconnection. If AGC has become inoperative, the Balancing Authority shall use manual control to adjust generation to maintain the Net Scheduled Interchange.
- R8.** The Balancing Authority shall ensure that data acquisition for and calculation of ACE occur at least every four seconds.
- R8.1.** Each Balancing Authority shall provide redundant and independent frequency metering equipment that shall automatically activate upon detection of failure of the primary source. This overall installation shall provide a minimum availability of 99.95%.
- R9.** The Balancing Authority shall include all Interchange Schedules with Adjacent Balancing Authorities in the calculation of Net Scheduled Interchange for the ACE equation.
- R9.1.** Balancing Authorities with a high voltage direct current (HVDC) link to another Balancing Authority connected asynchronously to their Interconnection may choose to omit the Interchange Schedule related to the HVDC link from the ACE equation if it is modeled as internal generation or load.
- R10.** The Balancing Authority shall include all Dynamic Schedules in the calculation of Net Scheduled Interchange for the ACE equation.
- R11.** Balancing Authorities shall include the effect of ramp rates, which shall be identical and agreed to between affected Balancing Authorities, in the Scheduled Interchange values to calculate ACE.
- R12.** Each Balancing Authority shall include all Tie Line flows with Adjacent Balancing Authority Areas in the ACE calculation.
- R12.1.** Balancing Authorities that share a tie shall ensure Tie Line MW metering is telemetered to both control centers, and emanates from a common, agreed-upon source using common primary metering equipment. Balancing Authorities shall ensure that megawatt-hour data is telemetered or reported at the end of each hour.
- R12.2.** Balancing Authorities shall ensure the power flow and ACE signals that are utilized for calculating Balancing Authority performance or that are transmitted for Regulation Service are not filtered prior to transmission, except for the Anti-Aliasing Filters of Tie Lines.
- R12.3.** Balancing Authorities shall install common metering equipment where Dynamic Schedules or Pseudo-Ties are implemented between two or more Balancing Authorities to deliver the output of jointly owned units or to serve remote load.

- R13.** Each Balancing Authority shall perform hourly error checks using Tie Line megawatt-hour meters with common time synchronization to determine the accuracy of its control equipment. The Balancing Authority shall adjust the component (e.g., Tie Line meter) of ACE that is in error (if known) or use the interchange meter error (I_{ME}) term of the ACE equation to compensate for any equipment error until repairs can be made.
- R14.** The Balancing Authority shall provide its operating personnel with sufficient instrumentation and data recording equipment to facilitate monitoring of control performance, generation response, and after-the-fact analysis of area performance. As a minimum, the Balancing Authority shall provide its operating personnel with real-time values for ACE, Interconnection frequency and Net Actual Interchange with each Adjacent Balancing Authority Area.
- R15.** The Balancing Authority shall provide adequate and reliable backup power supplies and shall periodically test these supplies at the Balancing Authority's control center and other critical locations to ensure continuous operation of AGC and vital data recording equipment during loss of the normal power supply.
- R16.** The Balancing Authority shall sample data at least at the same periodicity with which ACE is calculated. The Balancing Authority shall flag missing or bad data for operator display and archival purposes. The Balancing Authority shall collect coincident data to the greatest practical extent, i.e., ACE, Interconnection frequency, Net Actual Interchange, and other data shall all be sampled at the same time.
- R17.** Each Balancing Authority shall at least annually check and calibrate its time error and frequency devices against a common reference. The Balancing Authority shall adhere to the minimum values for measuring devices as listed below:

Device	Accuracy	
Digital frequency transducer	≤ 0.001	Hz
MW, MVAR, and voltage transducer	≤ 0.25	% of full scale
Remote terminal unit	≤ 0.25	% of full scale
Potential transformer	≤ 0.30	% of full scale
Current transformer	≤ 0.50	% of full scale

C. Measures

Not specified.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

IMC or, if formed by the Utilities, a Regional Reliability Organization.

Balancing Authorities shall be prepared to supply data to the IMC in the format defined below:

- 1.1.1.** Within one week upon request, Balancing Authorities shall provide the Regional Reliability Organization CPS source data in daily CSV files with time stamped one minute averages of: 1) ACE and 2) Frequency Error.

- 1.1.2. Within one week upon request, Balancing Authorities shall provide the IMC DCS source data in CSV files with time stamped scan rate values for: 1) ACE and 2) Frequency Error for a time period of two minutes prior to and thirty minutes after the identified Disturbance.

1.2. Compliance Monitoring Period and Reset Timeframe

Not specified.

1.3. Data Retention

- 1.3.1. Each Balancing Authority shall retain its ACE, actual frequency, Scheduled Frequency, Net Actual Interchange, Net Scheduled Interchange, Tie Line meter error correction and Frequency Bias Setting data in digital format at the same scan rate at which the data is collected for at least one year.
- 1.3.2. Each Balancing Authority or Reserve Sharing Group shall retain documentation of the magnitude of each Reportable Disturbance as well as the ACE charts and/or samples used to calculate Balancing Authority or Reserve Sharing Group disturbance recovery values. The data shall be retained for one year following the reporting quarter for which the data was recorded.

1.4. Additional Compliance Information

Not specified.

2. Levels of Non-Compliance

Level 2.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2016	No change in meaning	Defined terms

Alaska Railbelt Standard AKBAL-006-1 — Inadvertent Interchange

A. Introduction

1. Title: Inadvertent Interchange

2. Number: AKBAL-006-1

3. Purpose:

This standard defines a process for monitoring Balancing Authorities to ensure that, over the long term, Balancing Authority Areas do not excessively depend on other Balancing Authority Areas in the Interconnection for meeting their demand or Interchange obligations.

4. Applicability:

4.1. Balancing Authorities

5. Effective Date 6 months from package adoption

B. Requirements

R1. Each Balancing Authority shall calculate and record hourly Inadvertent Interchange.

R2. Each Balancing Authority shall include all tie lines that connect to its Adjacent Balancing Authority Areas in its Inadvertent Interchange account. The Balancing Authority shall take into account interchange served by jointly owned generators.

R3. Each Balancing Authority shall ensure all of its Balancing Authority Area interconnection points are equipped with common megawatt-hour meters, with readings provided hourly to the control centers of Adjacent Balancing Authorities.

R4. Adjacent Balancing Authority Areas shall operate to a common Net Interchange Schedule and Net Actual Interchange value and shall record these hourly quantities, with like values but opposite sign. Each Balancing Authority shall compute its Inadvertent Interchange based on the following:

R4.1. Each Balancing Authority, by the end of the next business day, shall agree with its Adjacent Balancing Authorities to:

R4.1.1. The hourly values of Net Interchange Schedule.

R4.1.2. The hourly integrated megawatt-hour values of Net Actual Interchange.

R4.2. Each Balancing Authority shall use the agreed-to daily and monthly accounting data to compile its monthly accumulated Inadvertent Interchange for the On-Peak and Off-Peak hours of the month.

R4.3. A Balancing Authority shall make after-the-fact corrections to the agreed-to daily and monthly accounting data only as needed to reflect actual operating conditions (e.g. a meter being used for control was sending bad data). Changes or corrections based on non-reliability considerations shall not be reflected in the Balancing Authority's Inadvertent Interchange. After-the-fact corrections to scheduled or actual values will not be accepted without agreement of the Adjacent Balancing Authorities.

Adjacent Balancing Authorities that cannot mutually agree upon their respective Net Actual Interchange or Net Scheduled Interchange quantities by the 15th calendar day of the following month shall, for the purposes of dispute

resolution, submit a report to their respective IMC representative. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy.

R5. Reserved for future use.

C. Measures

None Specified

D. Compliance Monitor

E. IMC or, if formed by the Utilities, a Regional Reliability Organization.Compliance

1. Compliance Monitoring Process

- 1.1.** Each Balancing Authority shall maintain a monthly summary of Inadvertent Interchange available to the IMC upon request. These summaries shall not include any after-the-fact changes that were not agreed to by the Source Balancing Authority, Sink Balancing Authority and all Intermediate Balancing Authorities.
- 1.2.** Inadvertent Interchange summaries shall include at least the previous accumulation, net accumulation for the month, and final net accumulation, for both the On-Peak and Off-Peak periods.
- 1.3.** Each Balancing Authority shall perform an Area Interchange Error (AIE) survey as requested by the IMC to determine the Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance. Data for such surveys shall be collected for the time period as specified by the IMC.

2. Levels of Non Compliance

A Balancing Authority that neither submits a report to the IMC, nor supplies a reason for not submitting the required data, when such report is requested shall be considered level 1 non-compliant.

F. Regional Differences

None identified

Version History

Version	Date	Action	Change Tracking
0	June 6, 2013	Original	New
1	May 2, 2016	Remove special Bradley Loss language	Modify

Alaska Standard AKBAL-502-Planning Resource Adequacy Analysis, Assessment and Documentation

A. Introduction

1. **Title:** Standard AKBAL-502-0 - Planning Resource Adequacy Analysis, Assessment and Documentation
2. **Number:** AKBAL-502-0
3. **Purpose:** To establish common criteria for each BA for a planning methodology based on the single largest unit contingency and an appropriate reserve margin or reserve criteria. The analysis, assessment, and documentation of Resource Adequacy, shall include Planning Reserve Margins for meeting system load both real and reactive within the Railbelt System.
4. **Applicability:**
 - 4.1. Balancing Authorities (BA)
 - 4.2. Planning Coordinators
5. **(Proposed) Effective Date:** TBD

B. Requirements

- R1.** The goal of the Resource Adequacy analysis is to plan the system to meet the following requirements annually.
- R1.1.** The Balancing Authority shall perform and document a Resource Adequacy analysis using one of the following two methods.

Method 1: The total capability of each Balance Authority's system plus the total amount of interruptible loads must be equal to or greater than the summation of the following:

- The capacity needed to serve the Forecasted Peak Demand for each period.
- The capacity of the unit(s) scheduled for maintenance for each period; and
- The capacity that would be lost by the Forced Outage of the largest unit/resource in service.

$$\sum_{i=1}^N N_i + L_{DR} \geq (L_{Peak} * F_{RM} + \sum_{m=1}^N N_m + N_{FO})$$

Where:

- N_i is the Normal Net Capability of available units.
- L_{DR} is the amount of Interruptible Demand designated and measureable for the BA's interruption that can be interrupted for the entire period of the expected capacity shortfall.
- L_{Peak} is the estimated system peak load and losses served from the available generation.
- N_m is the Normal Net Capability of units on scheduled maintenance.
- N_{FO} is the Normal Net Capability of the largest available unit(s) lost by Forced Outage.
- F_{RM} is the Reserve Margin multiplier and the BA must give consideration to using X percent (1.X) based on the reserve net capability. The Planning Coordinator shall set the required Reserve Margin multiplier (F_{RM}) for use in the Resource Adequacy analysis using Method 1 with approval by the IMC

However, in no case shall the selection of F_{RM} in relationship to Normal Net Capability of the largest available unit(s) cause a shortage to serve the estimated system peak load and losses.

Method 2: Calculate a Planning Reserve Margin that will result in the sum of the probabilities for the loss of Load for the integrated peak hour for all days of each planning year analyzed being equal to 0.X. (This is comparable to a “one day in X year” criterion). The Planning Coordinator shall set the minimum Loss of Load Expectation in days per year for use in the Resource Adequacy analysis using Method 2 with approval by the IMC.

R1.2. The Resource Adequacy analysis must document that the applicable Balancing Authority has developed a resource plan that meets the requirements of R1.1 Method 1 or R1.1 Method 2.

R1.2.1. The utilization of Interruptible Demand must not contribute to the loss of Load probability.

R1.2.2. The Planning Reserve Margin developed from R1.1 must be expressed as a percentage of the median¹ forecast peak Net Internal Demand (Planning Reserve Margin).

R1.3. Be performed or verified separately for each of the following planning years:

R1.3.1. Perform an analysis for Year One.

R1.3.2. Perform an analysis or verification at a minimum for one year in the 2 through 5 year period and at a minimum one year in the 6 through 10 year period.

¹ The median forecast is expected to have a 50% probability of being too high and 50% probability of being too low(50:50).

R1.3.2.1. If the analysis is verified, the verification must be supported by current or past studies for the same planning year.

R1.4. Include the following subject matter and documentation of its use:

R1.4.1. Load forecast characteristics:

- Median forecast peak Load.
- Load forecast uncertainty (reflects variability in the Load forecast due to weather and regional economic forecasts).
- Load diversity.
- Seasonal Load variations.
- Daily demand modeling assumptions (firm, interruptible).
- Contractual arrangements concerning curtailable/Interruptible Demand.
- Load response to frequency and short and long-term changes in voltage.

R1.4.2. Resource characteristics:

- Historic resource performance and any projected changes.
- Seasonal resource ratings.
- Resource planned outage schedules, deratings, and retirements.
- Modeling assumptions of intermittent and energy limited resource such as wind, PV, and cogeneration.
- Criteria for including planned resource additions in the analysis
- Starting/loading time if resources are to be used as Contingency Reserves
- Frequency response characteristics
- Inertia response characteristics
- Frequency ride-through characteristics
- Voltage ride-through characteristics
- Short circuit current characteristics
- Dispatch characteristics (ramp rate, minimum values, regulation, etc)
- Mitigation resources required due to generation capacity resource characteristics

R1.4.3. Transmission limitations that prevent the delivery of generation resources

R1.4.3.1. Criteria for including planned Transmission Facility additions in the analysis

R1.4.3.2. Criteria for remedial action systems employed in lieu of Transmission improvements

R1.4.3.3. Resource additions to eliminate or increase transfer capacity between areas or through a transmission path.

R1.5. Consider the following resource availability characteristics and document how and why they were included in the analysis or why they were not included:

- Availability and deliverability of fuel.
- Common mode outages that affect resource availability
- Environmental or regulatory restrictions of resource availability.
- Any other demand (Load) response programs not included in R1.3.1.
- Sensitivity to resource outage rates.
- Impacts of extreme weather/drought conditions that affect unit availability.
- Modeling assumptions for emergency operation procedures used to make reserves available.
- Market resources not committed to serving Load (uncommitted resources) within each Balance Authority's Control Area.

R1.6. Consider Transmission maintenance outage schedules and document how and why they were included in the Resource Adequacy analysis or why they were not included

R1.7. Document that capacity resources are appropriately accounted for in its Resource Adequacy analysis

R1.8. Document that all Load in the Balance Authority's Area is accounted for in its Resource Adequacy analysis

R1.9. Provide a Corrective Action Plan to meet the Planning Reserve Margin where Resource Adequacy Analysis shows a shortfall.

R1.9.1. Corrective Action Plan should consider transmission constraints when a generation asset is recommended.

R1.9.2. The Corrective Action Plan should consider Transmission improvements to remove generation constraints.

R1.9.2.1. If transmission improvements are part of the Resource Adequacy Corrective Action Plan, the Transmission improvements must be included in the appropriate Corrective Action Plan for the transmission system.

R2. Every five years or as determined by the IMC the BA must document the projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis.

R2.1. This documentation must cover each of the years selected for analysis or verification in R1.3.1 and R1.3.2.

R2.2. This documentation must include the Planning Reserve Margin calculated per requirement R1.1 for each of the three years in the analysis.

R2.3. The documentation as specified per requirement R2.1 and R2.2 must be publicly posted no later than 30 calendar days prior to the beginning of Year One.

R2.4. The documentation must include sufficient studies to show that the characteristics of proposed capacity addition do not result in a degradation of system performance.

C. Measures

M1. The BA must possess the documentation that a valid Resource Adequacy analysis was performed or verified in accordance with R1 Method 1 or R1 Method 2.

M2. The BA must possess the documentation of its projected Load and resource capability, for each area or Transmission constrained sub-area identified in the Resource Adequacy analysis on an annual basis in accordance with R2. The documentation must include sufficient studies to determine that the characteristics of the proposed resource additions do not degrade system performance or reliability.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.1.1. IMC or, if formed by the Utilities, a Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

1.2.1. One calendar year

1.3. Data Retention

1.3.1. The BA must retain information from the current analysis and the most recent analysis. The IMC (or designee) will retain any audit data for five years.

2. Levels of Non-Compliance for Requirement R1, Measure M1

2.1. Level 1 – The BA met one of the following conditions for Requirement R1 and Measurement M1.

2.1.1. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.4 and documentation of how and why they were included in the analysis or why they were not included.

- 2.1.2. The BA Resource Adequacy analysis failed to consider 1 or 2 of the Resource availability characteristics subcomponents under R1.5 and documentation of how and why they were included in the analysis or why they were not included.
 - 2.1.3. The BA Resource Adequacy analysis failed to consider Transmission maintenance outage schedules and document how and why they were included in the analysis or why they were not included per R1.6.
 - 2.1.4. The Planning Authority did not provide the minimum Reserve Margin multiplier or the minimum Loss of Load Expectation.
 - 2.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.
- 3. Levels of Non-Compliance for Requirement R2, Measure M2**
- 3.1. **Level 1** – The BA failed to publicly post the documents as specified per requirement R2.1 and R2.2 later than 30 calendar days prior to the beginning of Year One per R2.3 for Requirement R2 and Measurement M2.
 - 3.2. **Level 2** - The BA failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

Version History

Version	Date	Action	Change Tracking
000	11-1-2015	Adapted from Hawaii BAL-502 Standard	Yes
001	12-29-2015	Internal EPS edits	Yes
002	1-4-2016	Submitted for IMC review	Yes
003	1-25-2016	Submitted for IMC review	Yes
004	2-3-2016	Submitted for IMC review	Yes
Final	2-12-2016	IMC Final Revision	No

Alaska Railbelt Standard AKFAC-001-1 — Facility Connection Requirements

A. Introduction

1. Title: Facility Connection Requirements

2. Number: AKFAC-001-1

3. Purpose:

To avoid adverse impacts on reliability, Transmission Owners must establish facility connection and performance requirements. All entity's proposing to interconnect and operate equipment connected to the transmission owners' facilities within the Railbelt will be required to adhere to these standards.

4. Applicability:

4.1. Transmission Owner

5. Effective Date: 4 months from package adoption

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements that ensure compliance with the IMC Operating and Reliability Standards and applicable Regional Reliability Organization, sub-regional, power pool, and individual Transmission Owner planning criteria and facility connection requirements. The Transmission Owner's facility connection requirements shall address connection requirements for:

R1.1. Generation facilities,

R1.2. Transmission facilities, and

R1.3. End-user facilities.

R2. The Transmission Owner's facility connection requirements shall address, but are not limited to, the following items:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Procedures for coordinated joint studies of new facilities and their impacts on the interconnected transmission systems.

R2.1.2. Procedures for notification of new or modified facilities to others (those responsible for the reliability of the interconnected transmission systems) as soon as feasible.

R2.1.3. Voltage level and MW and MVAR capacity or demand at point of connection.

R2.1.4. Breaker duty and surge protection.

R2.1.5. System protection and coordination.

R2.1.6. Metering and telecommunications.

R2.1.7. Grounding and safety issues.

- R2.1.8.** Insulation and insulation coordination.
- R2.1.9.** Voltage, Reactive Power, and power factor control.
- R2.1.10.** Power quality impacts.
- R2.1.11.** Equipment Ratings.
- R2.1.12.** Synchronizing of facilities.
- R2.1.13.** Maintenance coordination.
- R2.1.14.** Operational issues (abnormal frequency and voltages).
- R2.1.15.** Inspection requirements for existing or new facilities.
- R2.1.16.** Communications and procedures during normal and Emergency operating conditions.

- R3.** The Transmission Owner shall maintain and update its facility connection requirements as required. The Transmission Owner shall make documentation of these requirements available to the users of the transmission system, the Regional Reliability Organization on request within five business days.

C. Measures

- M1.** The Transmission Owner shall make available to the IMC for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-1;R1.
- M2.** The Transmission Owner shall make available to the IMC for inspection evidence that it met all requirements stated in Reliability Standard AKFAC-001-1;R2.
- M3.** The Transmission Owner shall make available to the IMC for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-1;R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

- 1.2.** IMC or, if formed by the Utilities, a Regional Reliability Organization. **Compliance Monitoring Period and Reset Timeframe**
On request (five business days).

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

Level 3.

E. Regional Difference

None identified.

Version History

Version	Date	Action	Change Tracking
0	June 7, 2013	Original	New
1	May 2, 2016	Remove IMC interconnect standards	Modify

Alaska Railbelt Standard AKFAC-002-1 — Coordination of Plans for New Facilities

A. Introduction

- 1. Title:** **Coordination of Plans for New Generation, Transmission, and End User Facilities**
- 2. Number:** AKFAC-002-1
- 3. Purpose:**
To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements. All entity's proposing to interconnect and operate within the Railbelt will be required to adhere to these standards.
- 4. Applicability:**
 - 4.1.** Generator Owner.
 - 4.2.** Transmission Owner.
 - 4.3.** Distribution Provider.
 - 4.4.** Load-Serving Entity.
 - 4.5.** Transmission Planner.
 - 4.6.** Planning Authority.
- 5. Effective Date:** 4 months from package adoption

B. Requirements

- R1.** The Generator Owner, Transmission Owner, Distribution Provider, and Load-Serving Entity seeking to integrate generation facilities, transmission facilities, and electricity end-user facilities shall each coordinate and cooperate on its assessments with its Transmission Planner and Planning Authority. The assessment shall include:
 - R1.1.** Evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems.
 - R1.2.** Ensurance of compliance with the IMC's reliability standards and applicable Regional, subregional, power pool, and individual system planning criteria and facility connection requirements.
 - R1.3.** Evidence that the parties involved in the assessment have coordinated and cooperated on the assessment of the reliability impacts of new facilities on the interconnected transmission systems. While these studies may be performed independently, the results shall be jointly evaluated and coordinated by the entities involved.
 - R1.4.** Evidence that the assessment included steady-state, short-circuit, and dynamics studies as necessary to evaluate system performance.
 - R1.5.** Documentation that the assessment included study assumptions, system performance, alternatives considered, and jointly coordinated recommendations.

- R2.** The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each retain its documentation (of its evaluation of the reliability impact of the new facilities and their connections on the interconnected transmission systems) for three years and shall provide the documentation to the IMC on request (within 30 calendar days).

C. Measures

- M1.** The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider's documentation of its assessment of the reliability impacts of new facilities shall address all items in Reliability Standard AKFAC-002-0;R1.
- M2.** The Planning Authority, Transmission Planner, Generator Owner, Transmission Owner, Load-Serving Entity, and Distribution Provider shall each have evidence of its assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems is retained and provided to other entities in accordance with Reliability Standard AKFAC-002-0;R2.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

- 1.2.** IMC or, if formed by the Utilities, a Regional Reliability Organization. **Compliance Monitoring Period and Reset Timeframe**
On request (within 30 calendar days).

1.3. Data Retention

Evidence of the assessment of the reliability impacts of new facilities and their connections on the interconnected transmission systems: Three years.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

- 2.1. Level 1:** Assessments of the impacts of new facilities were provided, but were incomplete in one or more requirements of Reliability Standard AKFAC-002;R1.
- 2.2. Level 2:** Not applicable.
- 2.3. Level 3:** Not applicable.
- 2.4. Level 4:** Assessments of the impacts of new facilities were not provided.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	May 2, 2016	Remove gen & xmsn proforma	Modify

Alaska Railbelt Standard AKINT-001-0 — Interchange Information

A. Introduction

- 1. Title: Interchange Information**
- 2. Number:** AKINT-001-0
- 3. Purpose:**
Scheduled interchange must be coordinated between Balancing Authorities to prevent frequency deviations and accumulations of inadvertent interchange, and prevent exceeding mutually established transfer limits.
- 4. Applicability:**
 - 4.1.** Purchase-Selling Entities.
 - 4.2.** Balancing Authorities.
- 5. Effective Date:** 6 months from package adoption

B. Requirements

- R1.** Interchange shall be scheduled only between Balancing Authorities having directly connecting facilities in service unless there is a contract or mutual agreement with another Balancing Authority to provide connecting facilities.
- R2.** Interchange schedules or schedule changes shall not cause any other system to violate established reliability criteria.
 - R2.1.** When Balancing Authorities are connected so that parallel flows present reliability issues, the combinations of Balancing Authorities shall develop multi-control area interchange monitoring techniques and pre-determined corrective actions to mitigate or alleviate potential or actual transmission system overloads.
 - R2.2.** Transfer limits shall be reevaluated and interchange schedules adjusted as soon as practicable if transmission facilities become overloaded or are out of service, or when changes are made to the bulk system which can affect these limits.
- R3.** The maximum net scheduled interchange between two Balancing Authorities shall not exceed:
 - R3.1.** The total capacity of the transmission facilities in service between the two Balancing Authorities owned by them or available to them under specific arrangements, contract, or mutual agreements.
- R4.** The sending, contract intermediary, and receiving Balancing Authorities that are parties to an interchange transaction shall agree on the following:
 - R4.1.** The schedule's magnitude, starting and ending times.
 - R4.2.** The schedule's magnitude and rate of change shall be equal and opposite and not exceed the ability of the systems to effect the change.
 - R4.3.** The scheduled generation in one Balancing Authority that is delivered to another Balancing Authority must be scheduled with all intermediate Balancing Authorities unless there is a contract or mutual agreement among the sending, contract intermediary, and receiving Balancing Authorities to do otherwise.

- R5.** Balancing Authorities shall develop procedures to disseminate information on interchange schedules and facilities out of service which may have an adverse effect on other Balancing Authorities not involved in the scheduled interchange and the involved parties shall predetermine schedule priorities, which will be used if a schedule reduction becomes necessary.

C. Compliance

Level 1

D. Regional Differences

None identified

Version History

Version	Date	Action	Change Tracking
0	May 2, 2016	Original	New

Alaska Railbelt Standard AKMOD-025-2-Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

A. Introduction

Title: Verification and Data Reporting of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Number: AKMOD-025-2

Purpose: To ensure that accurate information on generator gross and net Real and Reactive Power capability and synchronous condenser Reactive Power capability is available for planning models used to assess Bulk Electric System (BES) reliability.

Applicability:

R1.1. Functional Entities:

R1.1.1. Generator Owner

R1.1.2. Transmission Planner

R1.1.3. Transmission Owner

R1.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an “applicable unit” that meet the following:

R1.2.1. Generation in the Interconnection with the following characteristics:

1.2.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

1.2.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

R1.2.2. Synchronous condenser greater than 5 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

R1.2.3. Power Electronics Transmission Assets greater than 1 MVA directly connected to the Bulk Electric System.

Effective Date:

TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

B. Requirements

- R1.** Each Generator Owner or Transmission Owner shall provide any Transmission Planner with verification of the Real Power capability of its applicable Facilities as follows:
- 1.1.** Verify, in accordance with Attachment 1, (i) the Real Power capability of its generating units and (ii) the Real Power capability of its Power Electronics Transmission Assets.; and
 - 1.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data; or
 - 1.3.** Submit a completed Attachment 3 (or a form containing the same information as identified in Attachment 3) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data for Temperature Sensitive Units.
- R2.** Each Generator Owner or Transmission Owner shall provide any Transmission Planner with verification of the Reactive Power capability of its applicable Facilities as follows:
- 2.1.** Verify, in accordance with Attachment 1, (i) the Reactive Power capability of its generating units, (ii) the Reactive Power capability of its synchronous condenser units, and (iii) the Reactive Power capability of its Power Electronics Transmission Assets.
 - 2.2.** Submit a completed Attachment 2 (or a form containing the same information as identified in Attachment 2) to any Transmission Planner within 60 calendar days of either (i) the date the data is recorded for a staged test; or (ii) the date the data is selected for verification using historical operational data.

C. Measures

- M1.** Each Generator Owner or Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or 3 or the Generator Owner or Transmission Owner form with the same information or dated information collected and used to complete attachments, and will have evidence that it submitted the information within 60 days to any Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R1. Each Generator Owner or Transmission Owner will have evidence that the Real Power capability was verified within the periodicity specified in Attachment 1.
- M2.** Each Generator Owner or Transmission Owner will have evidence that it performed the verification, such as a completed Attachment 2 or the Generator Owner or Transmission Owner form with the same information, or dated information collected and used to complete attachments and will have evidence that it submitted the information within 60 days to any Transmission Planner; such as dated electronic mail messages or mail receipts in accordance with Requirement R2. Each Generator Owner or Transmission Owner will have evidence that the Reactive Power capability was verified within the periodicity specified in Attachment 1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

IMC or, if formed by the Utilities, a Regional Reliability Organization.

1.2. Evidence Retention

The following evidence retention periods identify a period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention specified below is shorter than the time since the last compliance audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner and Transmission Owner shall each keep the data or evidence to show compliance as identified below, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Generator Owner shall retain the latest AKMOD-025 Attachment 2 or 3 and the data behind Attachment 2 or 3 or Generator Owner form with equivalent information and submittal evidence for Requirements R1 and R2, Measures M1 and M2 for the time period since the last compliance audit.
- The Transmission Owner shall retain the latest AKMOD-025 Attachment 2 and the data behind Attachment 2 or Transmission Owner form with equivalent information and submittal evidence for Requirements R3 and R4, Measure M3 and M4 for the time period since the last compliance audit.

If a Generator Owner or Transmission Owner is found noncompliant, it shall keep information related to the noncompliance until mitigation is complete or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Levels of Non-Compliance for Requirement R1, Measure M1

- 2.1.1. **Level 1** – The Generator Owner or Transmission Owner failed to provide any Transmission Planner with verification of the Real Power capability verification of its applicable Facilities within 60 days.
- 2.1.2. **Level 1** – The Generator Owner or Transmission Owner failed to meet the periodicity requirements of Attachment 1 for verification of its applicable Facilities.
- 2.1.3. **Level 2** – The Generator Owner or Transmission Owner failed to retain evidence that it performed the Real Power capability verification of its applicable Facilities as required by Requirement R1.

2.2. Levels of Non-Compliance for Requirement R2, Measure M2

- 2.2.1. **Level 1** – The Generator Owner or Transmission Owner failed to provide any Transmission Planner with verification of the Reactive Power capability of its applicable Facilities within 60 days.
- 2.2.2. **Level 1** – The Generator Owner or Transmission Owner failed to meet the periodicity requirements of Attachment 1 for verification of its applicable Facilities.
- 2.2.3. **Level 2** – The Generator Owner or Transmission Owner failed to retain evidence that it performed the Reactive Power capability verification of its applicable Facilities as required by Requirement R2.

Version History

Version	Date	Action	Change Tracking
0	-	NERC version	-
1	2-17-2016	EPS - initial edits	Yes
2	3-16-2016	EPS revision following 3/11/2016 meeting	Yes
3	9-16-2016	EPS revision following 8/25/2016 meeting	Yes
4	11-18-2016	EPS revision, addition of RCC	Yes
Final	12-06-2016	Final Version	no

AKMOD-025 Attachment 1 – Verification of Generator Real and Reactive Power Capability and Synchronous Condenser Reactive Power Capability

Periodicity for conduction of a new verification:

The periodicity for performing Real and Reactive Power capability verification is as follows:

1. For staged verification; verify each applicable Facility at least every five years or as approved by the IMC (with no more than 66 calendar months between verifications), or within 6 calendar months of the discovery of a change that affects its Real Power or Reactive Power capability by more than 10 percent of the last reported verified capability and is expected to last more than six months. The first verification for each applicable Facility under this standard must be a staged test.
2. For verification using operational data; verify each applicable Facility at least every calendar year or as approved by the IMC (with no more than 18 calendar months between verifications), or within 3 calendar months following the discovery that its Real Power or Reactive Power capability has changed by more than 10 percent of the last reported verified capability and is expected to last more than six months. For temperature sensitive units, verification of Real Power capability using operational data may require data over the course of several months. Operational data should be obtained within a string of consecutive months if allowable by ambient temperatures. If data for different points is recorded on different months, designate the earliest of those dates as the verification date, and report that date as the verification date on AKMOD-025, Attachment 2 for periodicity purposes. Units whose real power is verified using operational data shall confirm its Reactive Power using staged verifications.

For either verification method, verify each new applicable Facility within 6 calendar months of its commercial operation date or within a timeline approved by the IMC. Existing units that have been in long term shut down and have not been tested for more than five years shall be verified within 6 calendar months or within a timeline approved by the IMC if the units are scheduled to return to regular service.

It is intended that Real Power testing be performed at the same time as full load Reactive Power testing, however separate testing is allowed for this standard. For synchronous condensers, perform only the Reactive Power capability verifications as specified below. For all Power Electronics Transmission Assets perform Reactive Power capability verifications and perform real power verifications for Power Electronics Transmission Assets with real power capability.

If the Reactive Power capability is verified through test, it is to be scheduled at a time advantageous for the unit being verified to demonstrate its Reactive Power capabilities while the Transmission Operator takes measures to maintain the plant's system bus voltage at the scheduled value or within acceptable tolerance of the scheduled value.

Generators that have a current average Net Capacity Factor over the most recent three calendar years, beginning on January 1 and ending on December 31, of 5% or less are exempt. The equations for calculating the Net Capacity Factor are listed in AKMOD-027 Attachment 1 Note 4. The Generator Owner shall verify the capability within one year of the date of the capacity factor exemption expiration. The verification can be done by either a staged test or using operational data following the expiration of the capacity factor exemption.

Verification specifications for applicable Facilities:

1. For generating units of 5 MVA or less that are part of a plant greater than 5 MVA in aggregate connected through a single contingency condition, record data either on an individual unit basis or as a group. Perform verification individually for every generating unit or synchronous condenser greater than 5 MVA (gross nameplate rating). Perform verification individually for every Power Electronics Transmission Asset greater than 1 MVA.
2. Verify all auxiliary equipment needed for expected normal operation is in service for both the Real Power and Reactive Power capability verification. Perform verification with the automatic voltage regulator in service for the Reactive Power capability verification. Operational data from within the 18 months prior to the verification date is acceptable for the verification of either the Real Power or the Reactive Power capability, as long as a) that operational data meets the criteria in 2.1 through 2.4 below and b) the operational data demonstrates at least 90 percent of a previously staged test that demonstrated at least 50 percent of the Reactive capability shown on the associated thermal capability curve (D-curve). If the previously staged test was unduly restricted (so that it did not demonstrate at least 50 percent of the associated thermal capability curve) by unusual generation or equipment limitations (e.g., capacitor or reactor banks out of service), then the next verification will be by another staged test, not operational data:
 - 2.1. Verify Real Power capability and Reactive Power capability over-excited (lagging) of all applicable Facilities at the applicable Facilities' normal (not emergency) expected maximum Real Power output at the time of the verifications.
 - 2.1.1. Verify synchronous generating unit's maximum Real Power for one hour and lagging Reactive Power for a minimum of fifteen minutes.
 - 2.1.2. Verify Power Electronics Transmission Asset maximum Real Power. The verification should use greater than 20% of the rated energy at the rated Real Power output. The verification may use less than 20% of the rated energy with approval from the IMC.
 - 2.1.2.1. Verify that Power Electronics Transmission Assets used for Contingency Reserve have the capability to provide Contingency Reserve at the Real Power level for the expected duration.
 - 2.1.2.2. Verification of Power Electronics Transmission Assets used for Contingency Reserve may include staged tests or operational data.
 - 2.1.3. Verify variable generating units, such as wind, solar, and run of river hydro, at the maximum Real Power output the variable resource can provide at the time of the verification. Perform verification of Reactive Power capability of wind turbines and photovoltaic inverters with at least 90 percent of the wind turbines or photovoltaic inverters at a site on-line. If verification of wind turbines or photovoltaic inverter Facility cannot be accomplished meeting the 90 percent threshold, document the reasons the threshold was not met and test to the full capability at the time of the test. Reschedule the test of the facility within six months of being able to reach

the 90 percent threshold. Maintain, as steady as practical, Real and Reactive Power output during verifications.

- 2.2. Verify Reactive Power capability of all applicable Facilities, other than wind and photovoltaic, for maximum overexcited (lagging) and under-excited (leading) reactive capability for the following conditions:
 - 2.2.1. At the minimum Real Power output at which they are normally expected to operate collect maximum leading and lagging reactive values as soon as a limit is reached. The Reactive Power capability of Power Electronics Transmission Assets shall be verified at a Real Power output of zero if such devices are expected to provide reactive support.
 - 2.2.2. At maximum Real Power output collect maximum expected leading and lagging Reactive Power for 15 minutes.
- 2.3. For hydrogen-cooled generators, perform the verification at normal operating hydrogen pressure.
- 2.4. Calculate the Generator Step-Up (GSU) transformer losses if the verification measurements are taken from the high side of the GSU transformer. GSU transformer real and reactive losses may be estimated, based on the GSU impedance, if necessary.
3. Record the following data for the verifications specified above:
 - 3.1. The value of the gross Real and Reactive Power generating capabilities at the end of the verification period.
 - 3.2. The voltage schedule provided by the Transmission Operator, if applicable.
 - 3.3. The voltage at the high and low side of the GSU and/or system interconnection transformer(s) at the end of the verification period. If only one of these values is metered, the other may be calculated.
 - 3.4. The ambient conditions, if applicable, at the end of the verification period that the Generator Owner requires to perform corrections to Real Power for different ambient conditions such as:
 - Ambient air temperature
 - Relative humidity
 - Cooling water temperature
 - Other data as determined to be applicable by the Generator Owner to perform corrections for ambient conditions.
 - 3.5. The date and time of the verification period, including start and end time in hours and minutes.
 - 3.6. The existing GSU and/or system interconnection transformer(s) voltage ratio and tap setting.
 - 3.7. The GSU transformer losses (real or reactive) if the verification measurements were taken from the high side of the GSU transformer.
 - 3.8. Whether the test data is a result of a staged test or if it is operational data.

4. Develop a simplified key one-line diagram (refer to AKMOD-025, Attachment 2) showing sources of auxiliary Real and Reactive Power and associated system connections for each unit verified. Include GSU and/or system Interconnection and auxiliary transformers. Show Reactive Power flows, with directional arrows.
 - 4.1. If metering does not exist to measure specific Reactive auxiliary load(s), provide an engineering estimate and associated calculations. Transformer Real and Reactive Power losses will also be estimates or calculations. Only output data are required when using a computer program to calculate losses or loads.
5. If an adjustment is requested by the Transmission Planner, then develop the relationships between test conditions and generator output so that the amount of Real Power that can be expected to be delivered from a generator can be determined at different conditions, such as peak summer conditions. Adjust MW values tested to the ambient conditions specified by the Transmission Planner upon request and submit them to the Transmission Planner within 60 days of the request or the date the data was recorded/selected whichever is later.

Note 1: Under some transmission system conditions, the data points obtained by the MVAr verification required by the standard will not duplicate the manufacturer supplied thermal capability curve (D-curve) or power electronics capability curves. However, the verification required by the standard, even when conducted under these transmission system conditions, may uncover applicable Facility limitations; such as rotor thermal instability, improper tap settings or voltage ratios, inaccurate AVR operation, etc., which could be further analyzed for resolution. The MVAr limit level(s) achieved during a staged test or from operational data may not be representative of the unit's reactive capability for extreme system conditions. See Note 2.

Note 2: While not required by the standard, it is desirable to perform engineering analyses to determine expected applicable Facility capabilities under less restrictive system voltages than those encountered during the verification. Even though this analysis will not verify the complete thermal capability curve (D-curve) or power electronics capability curves, it provides a reasonable estimate of applicable Facility capability that the Transmission Planner can use for modeling.

Note 3: The Reactive Power verification is intended to define the limits of the unit's Reactive Power capabilities. If a unit has no leading capability, then it should be reported with no leading capability; or the minimum lagging capability at which it can operate.

Note 4: Synchronous Condensers and Power Electronics Transmission Assets without Real Power capability only need to be tested at two points (one over-excited point and one under-excited point) since they have no Real Power output.

AKMOD-025 Attachment 2

One-line Diagram, Table, and Summary for Verification Information Reporting

Note: If the configuration of the applicable Facility does not lend itself to the use of the diagram, tables, or summaries for reporting the required information, changes may be made to this form, provided that all required information (identified in AKMOD-025, Attachment 1) is reported.

Company:

Reported By (name):

Plant:

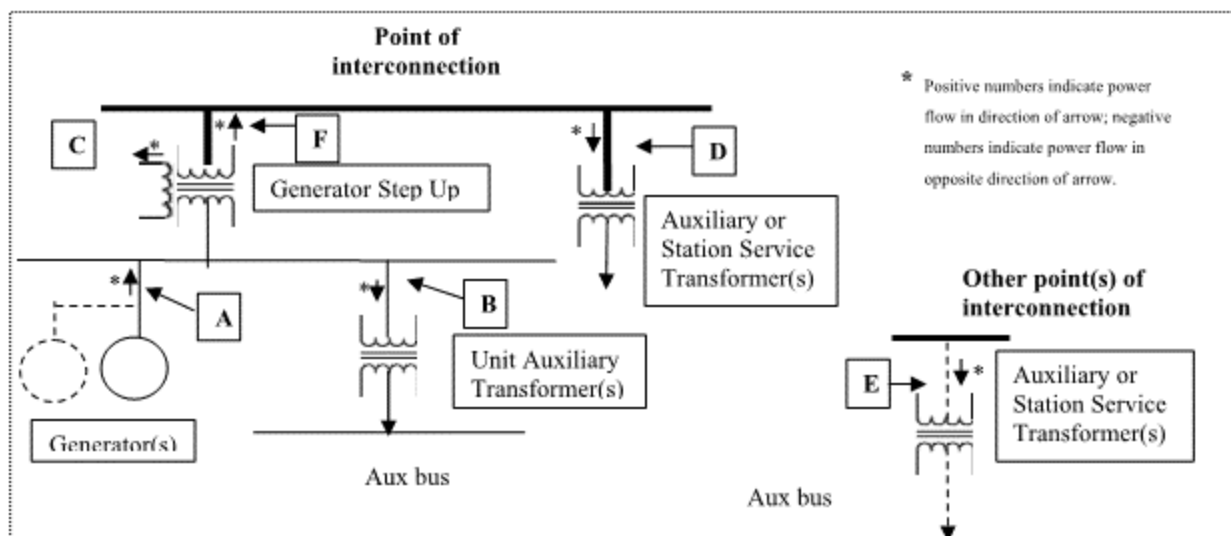
Unit No.:

Date of Report:

Check all that apply:

- ☐ Over-excited Full Load Reactive Power Verification
- ☐ Under-excited Full Load Reactive Power Verification
- ☐ Over-excited Minimum Load Reactive Power Verification
- ☐ Under-excited Minimum Load Reactive Power Verification
- ☐ Real Power Verification
- ☐ Staged Test Data
- ☐ Operational Data

Simplified one-line diagram showing plant auxiliary Load connections and verification data:



Point	Voltage	Real Power	Reactive Power	Comment
A	kV	MW	Mvar	Sum multiple generators that are verified together or are part of the same unit. Report individual unit values separately whenever the verification measurements were taken at the individual unit. Individual values are required for units or synchronous condensers > 5 MVA or Power Electronics Transmission Assets > 1 MVA.
Identify calculated values if any:				
B	kV	MW	Mvar	Sum multiple unit auxiliary transformers.
Identify calculated values if any:				
C	kV	MW	Mvar	Sum multiple tertiary Loads, if any.
Identify calculated values if any:				
D	kV	MW	Mvar	Sum multiple auxiliary and station service transformers.
Identify calculated values if any:				
E	kV	MW	Mvar	If multiple points of Interconnection, describe these for accurate modeling; report points individually (sum multiple auxiliary transformers).
F	kV	MW	Mvar	Net unit capability
Identify calculated values if any:				

AKMOD-025 – Attachment 2 (continued)

Verification Data

Provide data by unit or Facility as appropriate

Data Type	Data Recorded	Last Verification (Previous Data; will be blank for the initial verification)
Gross Reactive Power Capability (*Mvar)		
Aux Reactive Power (*Mvar)		
Net Reactive Power Capability (*Mvar) equals Gross Reactive Power Capability (*Mvar) minus Aux Reactive Power connected at the same bus (*Mvar) minus tertiary Reactive Power connected at the same bus(*Mvar)		
Gross Real Power Capability (*MW)		
Aux Real Power (*MW)		
Net Real Power Capability (*MW) equals Gross Real Power Capability (*MW) minus Aux Real Power connected at the same bus (*MW) minus tertiary Real Power connected at the same bus (*MW)		
* Note: Enter values at the end of the verification period.		
GSU losses (only required if verification measurements are taken on the high side of the GSU - Mvar)		

Summary of Verification

- Date of Verification _____, Verification Start Time _____, Verification End Time _____
- Scheduled Voltage _____
- Transformer Voltage Ratio: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Transformer Tap Setting: GSU _____, Unit Aux _____, Station Aux _____, Other Aux _____
- Ambient conditions at the end for the verification period:
 - 3. Air Temperature: _____
 - 4. Humidity: _____
 - 5. Cooling water temperature: _____
 - 6. Other data as applicable: _____
- Generator hydrogen pressure at time of test (if applicable) _____

Date that data shown in last verification column in table above was taken _____

Remarks :

Note: If the verification value did not reach the thermal capability curve (D-curve), describe the reason.

AKMOD-025 – Attachment 3

The Real Power capability verification for Temperature Sensitive Units shall be performed as follows:

1. The Real Power capability verification for Temperature Sensitive Units shall occur annually or as approved by the IMC.
2. Real Power verification shall be performed for generating units 5 MVA or larger or generating units smaller than 5 MVA that are part of a plant greater than 5 MVA in aggregate connected through a single contingency condition.
3. Verify with all auxiliary equipment needed for expected normal operation in service for the Real Power capability verification.
 - 3.1. Verify Real Power capability of all applicable Facilities at the applicable Facilities' maximum Real Power output for the ambient air temperature at the time of the verification.
 - 3.1.1. Verify Temperature Sensitive Unit's maximum real power for a minimum of fifteen minutes.
 - 3.1.2. Verification shall be performed at ambient air temperature increments of 10 degrees Fahrenheit from annual minimum temperature to the annual maximum temperature at the unit location.
 - 3.1.3. Verification data shall include the Temperature Sensitive Unit's maximum real power, the temperature in Fahrenheit, and the time and date of test.
4. Record the following data for the verifications specified above:
 - 4.1. The value of the gross Real Power generating capabilities at the end of the verification period.
 - 4.2. The auxiliary power, temperature, date, and time of test for applicable Temperature Sensitive Unit.

Data Type	Data Recorded	Temperature	Date	Time
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____
Gross Power Capability, Aux Power	_____ MW, _____ MW	_____ °F	_____	_____

Alaska Railbelt Standard AKMOD-026-1- Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

A. Introduction

Title: Verification of Models and Data for Generator Excitation Control System or Plant Volt/Var Control Functions

Number: AKMOD-026-1

Purpose: To verify that the generator excitation control system or plant volt/var control function² model (including the power system stabilizer model and the impedance compensator model) and the model parameters used in dynamic simulations accurately represent the generator excitation control system or plant volt/var control function behavior when assessing Bulk Electric System (BES) reliability.

Applicability:

R6.1. Functional Entities:

R6.1.1. Generator Owner

R6.1.2. Transmission Planner

R6.1.3. Transmission Owner

R6.2. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred as an “applicable unit” that meet the following:

R6.2.1. Generation in the Interconnection with the following characteristics:

6.2.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

6.2.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

R6.2.2. Synchronous condenser greater than 5 MVA (gross nameplate rating) directly connected to the Bulk Electric System.

R6.2.3. Power Electronics Transmission Assets greater than 1 MVA directly connected to the Bulk Electric System.

Effective Date:

TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

² Excitation control system or plant volt/var control function:

- a. For individual synchronous machines, the generator excitation control system includes the generator, exciter, voltage regulator, impedance compensation and power system stabilizer.
- b. For an aggregate generating plant, the volt/var control system includes the voltage regulator & reactive power control system controlling and coordinating plant voltage and associated reactive capable resources.

B. Requirements

R1. Each Transmission Planner shall provide the following information to the Generator Owner or Transmission Owner within 30 calendar days of receiving a written request:

- Instructions on how to obtain the list of excitation control system or plant volt/var control function models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic excitation control system or plant volt/var control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's or Transmission Owner's existing applicable unit specific excitation control system or plant volt/var control function contained in the Transmission Planner's dynamic database from the current (in-use) models, including generator MVA base.

R2. Each Generator Owner shall provide for each applicable unit, a verified generator excitation control system or plant volt/var control function model, including documentation and data (as specified in Part 2.1) to any Transmission Planner in accordance with the periodicity specified in AKMOD-026 Attachment 1. Transmission Owners shall provide the same documentation and data for applicable Power Electronics Transmission Assets.

R1.1. Each applicable unit's model shall be verified by the Generator Owner or Transmission Owner using one or more models acceptable to the Transmission Planner. Verification for individual units less than 5 MVA (gross nameplate rating, 1 MVA for Power Electronics Transmission Assets) in a generating plant (per Section 4.2.1.2) may be performed using either individual unit or aggregate unit model(s), or both. Each verification shall include the following:

- R2.1.1.** Documentation demonstrating the applicable unit's model response matches the recorded response for a voltage excursion from either a staged test or a measured system disturbance,
- R2.1.2.** Manufacturer, model number (if available), and type of the excitation control system including, but not limited to static, AC brushless, DC rotating, and/or the plant volt/var control function (if installed),
- R2.1.3.** Model structure and data including, but not limited to reactance, time constants, saturation factors, total rotational inertia, or equivalent data for the generator,
- R2.1.4.** Model structure and data for the excitation control system, including the closed loop voltage regulator if a closed loop voltage regulator is installed or the model structure and data for the plant volt/var control function system,
- R2.1.5.** Compensation settings (such as droop, line drop, differential compensation), if used, and
- R2.1.6.** Model structure and data for power system stabilizer, if so equipped,

R2.1.7. Model for plant control system, including control parameters used to control plant voltage/var output, including mode or control switching due to off-schedule voltage or var output.

R2.1. Each Generator Owner or Transmission Owner shall provide model structure, data, and source code (if available) for any excitation control system or plant volt/var control function that requires a custom model that is not in the model list provided by the Transmission Planner.

R2.2.1. The Generator Owner or Transmission Owner shall document the need for using a custom model and provide the documentation to the Transmission Planner.

R3. Each Generator Owner or Transmission Owner shall provide a written response to any Transmission Planner within 60 calendar days of receiving one of the following items for an applicable unit:

- Written notification from any Transmission Planner (in accordance with Requirement R6) that the excitation control system or plant volt/var control function model is not usable,
- Written comments from any Transmission Planner identifying technical concerns with the verification documentation related to the excitation control system or plant volt/var control function model, or
- Written comments and supporting evidence from any Transmission Planner indicating that the simulated excitation control system or plant volt/var control function model response did not match the recorded response to a transmission system event.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification³ (in accordance with Requirement R2).

R4. Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification (in accordance with Requirement R2) for an applicable unit to any Transmission Planner within 60 calendar days of making changes to the excitation control system or plant volt/var control function that alter the equipment response characteristic⁴.

R5. Each Generator Owner and Transmission Owner shall provide a written response to any Transmission Planner, within 60 calendar days following receipt of a technically justified⁵ unit request from the Transmission Planner to perform a model review of a unit or plant that includes one of the following:

³ If verification is performed, the 5-year period as outlined in AKMOD-026 Attachment 1 is reset.

⁴ Exciter, voltage regulator, plant volt/var or power system stabilizer control replacement including software alterations that alter excitation control system equipment response, plant digital control system addition or replacement, plant digital control system software alterations that alter excitation control system equipment response, plant volt/var function equipment addition or replacement (such as static var systems, capacitor banks, individual unit excitation systems, etc), a change in the voltage control mode (such as going from power factor control to automatic voltage control, etc), exciter, voltage regulator, impedance compensator, or power system stabilizer settings change. Automatic changes in settings that occur due to changes in operating mode do not apply to Requirement R4.

⁵ Technical justification is achieved by the Transmission Planner demonstrating that the simulated unit or plant response does not match the measured unit or plant response.

- Details of plans to verify the model (in accordance with Requirement R2), or
 - Corrected model data including the source of revised model data such as discovery of manufacturer test values to replace generic model data or updating of data parameters based on an on-site review of the equipment.
- R6.** Each Transmission Planner shall provide a written response to the Generator Owner or Transmission Owner within 30 calendar days of receiving the verified excitation control system or plant volt/var control function model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 6.1 through 6.3) or is not usable.
- R3.1.** The excitation control system or plant volt/var control function model initializes to compute modeling data without error,
- R4.1.** A no-disturbance simulation results in negligible transients, and
- R5.1.** For an otherwise stable simulation, a disturbance simulation results in the excitation control and plant volt/var control function model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.

C. Measures

- M1.** The Transmission Planner must provide the dated request for instructions or data, the transmitted instructions or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 30 calendar days in accordance with Requirement R1.
- M2.** The Generator Owner or Transmission Owner must provide dated evidence it verified each generator excitation control system or plant volt/var control function model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.
- M3.** Evidence for Requirement R3 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.
- M4.** Evidence for Requirement R4 must include, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, a dated revised model data or plans to perform a model verification and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided the revised model and data or plans within 60 calendar days of making changes.
- M5.** Evidence for Requirement R5 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R5 and dated evidence (e.g., electronic mail message, postal receipt, or confirmation of facsimile) it provided a written response within 30 calendar days following receipt of a technically justified request.

- M6.** Evidence of Requirement R6 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 6.1 through 6.3 and for a model that is not usable, a technical description; and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R6, Measures M1 and M6 for three calendar years from the date the document was provided.
- The Generator Owner or Transmission Owner shall retain the latest excitation control system or plant volt/var control function model verification evidence of Requirement R2, Measure M2.
- The Generator Owner or Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3 through R5, and Measures M3 through M5 for three calendar years from the date the document was provided.

If a Generator Owner, Transmission Owner, or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete or approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

E. Regional Variances

None.

F. Associated Documents

None.

Version History

Version	Date	Action	Change Tracking
0	-	NERC version	-
1	2-23-2016	EPS edit from NERC standard	Yes
2	3-16-2016	EPS edit	Yes
3	9-16-2016	EPS edit following 8/25/2016 meeting	Yes
4	11-18-2016	EPS revision, addition of RCC	Yes
Final	12-06-2016	Final Version	no

AKMOD-26 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 4 applies when calculating generation fleet compliance during the 5-year implementation period See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 5-year anniversary of the last transmittal (per Note 1).
3	Initial verification for a new applicable unit or for an existing applicable unit with new excitation control system or plant volt/var control function equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 90 calendar days after the commissioning date.

AKMOD-26 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
4	Existing applicable unit that is equivalent to another unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 30 MVA or 2 MVA for Power Electronics Transmission Assets. AND Each applicable unit has the same components and settings. AND The model for one of these equivalent applicable units has been verified.	Document circumstance with a written statement and include with the verified model, documentation, and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 5-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.
5	The Generator Owner or Transmission Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 60-calendar days after the model verification.

AKMOD-26 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
6	New or existing applicable unit does not include an active closed loop voltage or reactive power control function. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 3 for a “New Generating Unit” (or new equipment) only if active closed loop function is established. See Footnote 1 (see Section A.3) for clarification of what constitutes an active closed loop function for both conventional synchronous machines (reference Footnote 1a) and aggregate generating plants (reference Footnote 1b).
7	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. Existing Power Electronics Transmission Assets was available for less than 10% of the most recent one year, beginning on January 1 and ending on December 31. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 5-year timeframe, the current average three year net capacity factor (for years 3, 4, and 5) can be examined to determine if the capacity factor exemption can be declared for the next 5-year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Note 3.

AKMOD-26 Attachment 1		
Excitation Control System or Plant Volt/Var Function Model Verification Periodicity		
Row Number	Verification Condition	Required Action
NOTES: NOTE 1: Establishing the recurring 5-year unit verification period start date: The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification. NOTE 2: Consideration for early compliance: Existing generator excitation control system or plant volt/var control function model verification is sufficient for demonstrating compliance for a 5-year period from the actual transmittal date if either of the following applies: ☐ The Generator Owner or Transmission Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification. • The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard. NOTE 3: Net Capacity Factor Equations: $\text{Equation 1: } NCF = \frac{\text{Net Actual Generation}}{PH * NMC} * 100\%$ $\text{Equation 2: } NCF = \frac{\sum(\text{Net Actual Generation})}{\sum(PH * NMC)} * 100\%$ Where: ☐ PH = Period Hours (Number of hours in the period being reported that the unit was in the active state) ☐ NMC = Net Maximum Capacity • Equation 2 is an energy-weighted equation. Use Equation 2 when calculating for a group of units (or a unit that has a varying capacity value over time), do not simply average these factors. Follow Equation 2		

Alaska Railbelt Standard AKMOD-027- Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

A. Introduction

Title: Verification of Models and Data for Turbine/Governor and Load Control or Active Power/Frequency Control Functions

Number: AKMOD-027-1

Purpose: To verify that the turbine/governor and load control or active power/frequency control⁶ model and the model parameters, used in dynamic simulations that assess Bulk Electric System (BES) reliability, accurately represent generator unit real power response to system frequency variations.

Applicability:

R6.3. Functional Entities:

R6.3.1. Generator Owner

R6.3.2. Transmission Planner

R6.3.3. Transmission Owner

R6.4. Facilities:

For the purpose of the requirements contained herein, Facilities that are directly connected to the Bulk Electric System (BES) will be collectively referred to as an “applicable unit” that meet the following:

R6.4.1. Generation in the Interconnection with the following characteristics:

6.4.1.1. Individual generating unit greater than 5 MVA (gross nameplate rating).

6.4.1.2. Individual generating plant consisting of multiple generating units that are directly connected at a common BES bus with total generation greater than 5 MVA (gross aggregate nameplate rating).

R6.4.2. Power Electronics Transmission Assets with Real Power capabilities greater than 1 MVA directly connected to the Bulk Electric System.

Effective Date:

TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

⁶ Turbine/governor and load control or active power/frequency control:

- a. Turbine/governor and load control applies to conventional synchronous generation.
- b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

B. Requirements

R1. Each Transmission Planner shall provide the following information to the Generator Owner or Transmission Owner within 30 calendar days of receiving a written request:

- Instructions on how to obtain the list of turbine/governor and load control or active power/frequency control system models that are acceptable to the Transmission Planner for use in dynamic simulation,
- Instructions on how to obtain the dynamic turbine/governor and load control or active power/frequency control function model library block diagrams and/or data sheets for models that are acceptable to the Transmission Planner, or
- Model data for any of the Generator Owner's or Transmission Owner's existing applicable unit specific turbine/governor and load control or active power/frequency control system contained in the Transmission Planner's dynamic database from the current (in-use) models.
- It is noted that digital governors with multiple modes of control and operation may require the Generation Owner or Transmission Owner to develop custom models to simulate the response of the unit. Such models will be based on standard models provided by the Transmission Planner to the extent possible.

R2. Each Generator Owner shall provide, for each applicable unit, a verified turbine/governor and load control or active power/frequency control model, including documentation and data (as specified in Part 2.1) to any Transmission Planner in accordance with the periodicity specified in MOD-027 Attachment 1. Transmission Owners shall provide the same documentation and data for applicable Power Electronics Transmission Assets.

R2.1. Each applicable unit's model shall be verified by the Generator Owner or Transmission Owner using one or more models acceptable to the Transmission Planner. Verification for individual units rated less than 5 MVA (gross nameplate rating, 1 MVA for Power Electronics Transmission Assets) in a generating plant (per Section 4.2.1.2) may be performed using either individual unit or aggregate unit model(s) or both. Each verification shall include the following:

R2.1.1. Documentation comparing the applicable unit's MW model response to the recorded MW response for either:

- A frequency excursion from a system disturbance that meets MOD-027 Attachment 1 Note 1 with the applicable unit on-line,
- A speed governor reference change with the applicable unit online, or
 - For staged tests, the governor reference change should occur at multiple operating points including minimum,

peak load, and near peak load to show the impact that unit output has on the unit response to a reference change.

- Staged tests shall include verification of governor performance for each mode transition, including transitions back from transient mode if applicable for system modeling.

- A partial load rejection test,⁷

R2.1.2. Type of governor and load control or active power control/frequency control⁸ equipment,

R2.1.3. A description of the turbine (e.g. for hydro turbine - Kaplan, Francis, or Pelton; for steam turbine - boiler type, normal fuel type, and turbine type; for gas turbine - the type and manufacturer; for variable energy plant - type and manufacturer; for Power Electronics Transmission Asset – type and manufacturer),

R2.1.4. Model structure and data for turbine/governor and load control or active power/frequency control,

R2.1.5. Description and recommended modeling method for any governor actions that would limit the active power or change governor control modes including, but not limited to:

- Temperature limiters
- Pressure limiters
- Rate limiters

R2.1.6. Description and recommended modeling method for any governor response resulting from a control mode change within the governor during on-line operations. All control mode changes must be included in the recommended modeling method.

R2.1.7. Representation of the real power response effects of outer loop controls (such as operator set point controls, and load control but excluding AGC control) that would override the governor response

⁷ Differences between the control mode tested and the final simulation model must be identified, particularly when analyzing load rejection data. Most controls change gains or have a set point runback which takes effect when the breaker opens. Load or set point controls will also not be in effect once the breaker opens. Some method of accounting for these differences must be presented if the final model is not validated from on-line data under the normal operating conditions under which the model is expected to apply.

⁸ Turbine/governor and load control or active power/frequency control:

- a. Turbine/governor and load control applies to conventional synchronous generation.
- b. Active power/frequency control applies to inverter connected generators (often found at variable energy plants).

(including blocked or nonfunctioning governors or modes of operation that limit Frequency Response), if applicable.

R2.2. Each Generator Owner or Transmission Owner shall provide model structure, data, and source code (if available) for any turbine/governor and load control or active power/frequency control function model that requires a custom model that is not in the model list provided by the Transmission Planner.

R2.2.1. The Generator Owner or Transmission Owner shall document the need for using a custom model and provide the documentation to the Transmission Planner.

R3. Each Generator Owner or Transmission Owner shall provide a written response to any Transmission Planner within 60 calendar days of receiving one of the following items for an applicable unit.

- Written notification, from any Transmission Planner (in accordance with Requirement R5) that the turbine/governor and load control or active power/frequency control model is not “usable,”
- Written comments from any Transmission Planner identifying technical concerns with the verification documentation related to the turbine/governor and load control or active power/frequency control model, or
- Written comments and supporting evidence from any Transmission Planner indicating that the simulated turbine/governor and load control or active power/frequency control response did not approximate the recorded response for three or more transmission system events.

The written response shall contain either the technical basis for maintaining the current model, the model changes, or a plan to perform model verification⁹ (in accordance with Requirement R2).

R4. Each Generator Owner or Transmission Owner shall provide revised model data or plans to perform model verification (in accordance with Requirement R2) for an applicable unit to any Transmission Planner within 60 calendar days of making changes to the turbine/governor and load control or active power/frequency control system that alter the equipment response characteristic¹⁰.

R5. Each Transmission Planner shall provide a written response to the Generator Owner or Transmission Owner within 30 calendar days of receiving the turbine/governor and load control or active power/frequency control system verified model information in accordance with Requirement R2 that the model is usable (meets the criteria specified in Parts 5.1 through 5.3) or is not usable.

⁹ If verification is performed, the 5 year period as outlined in MOD-027 Attachment 1 is reset.

¹⁰ Control replacement or alteration including software alterations or plant digital control system addition or replacement, plant digital control system software alterations that alter droop, and/or dead band, and/or frequency response and/or a change in the frequency control mode (such as going from droop control to constant MW control, etc).

- R5.1.** The turbine/governor and load control or active power/frequency control function model initializes to compute modeling data without error,
- R5.2.** A no-disturbance simulation results in negligible transients, and
- R5.3.** For an otherwise stable simulation, a disturbance simulation results in the turbine/governor and load control or active power/frequency control model exhibiting positive damping.

If the model is not usable, the Transmission Planner shall provide a technical description of why the model is not usable.

C. Measures

- M1.** The Transmission Planner must provide the dated request for instructions or data, the transmitted instruction or data, and dated evidence of a written transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence that it provided the request within 30 calendar days in accordance with Requirement R1.
- M2.** The Generator Owner or Transmission Owner must provide dated evidence it verified each generator turbine/governor and load control or active power/frequency control model according to Part 2.1 for each applicable unit and a dated transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) as evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.
- M3.** Evidence for Requirement R3 must include the Generator Owner's or Transmission Owner's dated written response containing the information identified in Requirement R3 and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) of the response.
- M4.** Evidence for Requirement R4 must include, for each of the Generator Owner's or Transmission Owner's applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification and dated evidence of transmittal (e.g., electronic mail message, postal receipt, or confirmation of facsimile) within 60 calendar days of making changes.
- M5.** Evidence of Requirement R5 must include, for each model received, the dated response indicating the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3 and for a model that is not useable, a technical description that the model is not usable, and dated evidence of transmittal (e.g., electronic mail messages, postal receipts, or confirmation of facsimile) that the Generator Owner or Transmission Owner was notified within 30 calendar days of receipt of model information in accordance with Requirement R5.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. Data Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The Generator Owner, Transmission Owner, and Transmission Planner shall each keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- The Transmission Planner shall retain the information/data request and provided response evidence of Requirements R1 and R5, Measures M1 and M5 for 3 calendar years from the date the document was provided.
- The Generator Owner or Transmission Owner shall retain the latest turbine/governor and load control or active power/frequency control system model verification evidence of Requirement R2, Measure M2.
- The Generator Owner or Transmission Owner shall retain the information/data request and provided response evidence of Requirements R3, and R4 Measures M3 and M4 for 3 calendar years from the date the document was provided.

If a Generator Owner, Transmission Owner, or Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaint

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Levels of Non-Compliance for Requirement R1, Measure M1

- 2.1.1. Level 1** – The Transmission Planner failed to retain dated evidence that it provided the requested information within 30 calendar days in accordance with Requirement R1.
- 2.1.2. Level 2** – The Transmission Planner failed to provide the Generator Owner or Transmission Owner with the requested information in accordance with Requirement R1.

2.2. Levels of Non-Compliance for Requirement R2, Measure M2

- 2.2.1 Level 1** - The Generator Owner or Transmission Owner failed to retain dated evidence it provided the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.
- 2.2.2 Level 2** - The Generator Owner, or Transmission Owner failed to provide the model, documentation, and data to any Transmission Planner, in accordance with Requirement R2.

2.3. Levels of Non-Compliance for Requirement R3, Measure M3

- 2.3.1 Level 1** – The Generator Owner, or Transmission Owner failed to retain dated evidence showing it responded to the Transmission Planner and provided the information identified in Requirement R3.
- 2.3.2 Level 2** – The Generator Owner, or Transmission Owner failed to respond to the Transmission Planner with the information identified in Requirement R3.

2.4. Levels of Non-Compliance for Requirement R4, Measure M4

- 2.4.1 Level 1** – The Generator Owner, or Transmission Owner failed to retain evidence which includes, for each of the Generator Owner’s or Transmission Owner’s applicable units for which system changes specified in Requirement R4 were made, dated revised model data or dated plans to perform a model verification.

2.5. Levels of Non-Compliance for Requirement R5, Measure M5

- 2.5.1 Level 1** – The Transmission Planner failed to retain dated response to the Generator Owner or Transmission Owner which must include, for each model received, an indication that the model was usable or not usable according to the criteria specified in Parts 5.1 through 5.3.

E. Regional Variances

None

F. Associated Documents

None

Version History

Version	Date	Action	Change Tracking
0	-	NERC Version	-
1	2-23-2016	EPS edit from NERC standards	Yes
2	3-16-2016	EPS edit	Yes
3	9-16-2016	EPS edit following 8/25/2016 meeting	Yes
4	11-18-2016	EPS revision, addition of RCC	Yes
Final	12-06-2016	Final Version	no

AKMOD-27 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
1	Establishing the initial verification date for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the Effective Date. Row 5 applies when calculating generation fleet compliance during the 5 year implementation period. See Section A5 for Effective Dates.
2	Subsequent verification for an applicable unit. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner on or before the 5-year anniversary of the last transmittal (per Note 2).
3	Applicable unit was not subjected to a frequency excursion per Note 1 with available generating capacity available to show Governor or Load Control response by the date otherwise required to meet the dates per Rows 1, 2, 4, or 6. (This row is only applicable if a frequency excursion from a system disturbance that meets Note 1 is selected for the verification method and the ability to record the applicable unit's real power response to a frequency excursion is installed and expected to be available). (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Transmit the verified model, documentation and data to the Transmission Planner on or before 60 calendar days after a frequency excursion per Note 1 occurs and the recording equipment captures the applicable unit's real power response as expected.
4	Initial verification for a new applicable unit or for an existing applicable unit with new turbine/governor and load control or active power/frequency control equipment installed. (Requirement R2)	Transmit the verified model, documentation and data to the Transmission Planner within 90 calendar days after the commissioning date.

AKMOD-27 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
5	Existing applicable unit that is equivalent to another applicable unit(s) at the same physical location. AND Each applicable unit has the same MVA nameplate rating. AND The nameplate rating is ≤ 30 MVA or 2 MVA for Power Electronics Transmission Assets. AND Each applicable unit has the same components and settings; AND The model for one of these equivalent applicable units has been verified. (Requirement R2)	Document circumstance with a written statement and include with the verified model, documentation and data provided to the Transmission Planner for the verified equivalent unit. Verify a different equivalent unit during each 5-year verification period. Applies to Row 1 when calculating generation fleet compliance during the 5-year implementation period.
6	The Generator Owner or Transmission Owner has submitted a verification plan. (Requirement R3, R4 or R5)	Transmit the verified model, documentation and data to the Transmission Planner within 60 calendar days after the model verification.

AKMOD-27 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
7	Applicable unit is not responsive to both over and under frequency excursion events (The applicable unit does not operate in a frequency control mode, except during normal start up and shut down, that would result in a turbine/governor and load control or active power/frequency control mode response.); OR Applicable unit either does not have an installed frequency control system or has a disabled frequency control system. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. Perform verification per the periodicity specified in Row 4 for a "New Generating Unit" (or new equipment) only if responsive control mode operation for connected operations is established.
8	Existing applicable unit has a current average net capacity factor over the most recent three calendar years, beginning on January 1 and ending on December 31 of 5% or less. Existing Power Electronics Transmission Assets was available for less than 10% of the most recent one year, beginning on January 1 and ending on December 31. (Requirement R2)	Requirement 2 is met with a written statement to that effect transmitted to the Transmission Planner. At the end of this 5 calendar year timeframe, the current average three year net capacity factor (for years 3, 4, and 5) can be examined to determine if the capacity factor exemption can be declared for the next 5 calendar year period. If not eligible for the capacity factor exemption, then model verification must be completed within 365 calendar days of the date the capacity factor exemption expired. For the definition of net capacity factor, refer to Note 4.

AKMOD-27 Attachment 1		
Turbine/Governor and Load Control or Active Power/Frequency Control Model Periodicity		
Row Number	Verification Condition	Required Action
NOTES: NOTE 1: Unit model verification frequency excursion criteria: ☐ ≥ 0.30 hertz deviation (nadir point) from scheduled frequency for the Interconnection with the applicable unit operating in a frequency responsive mode NOTE 2: Establishing the recurring 5 year unit verification period start date: ☐ The start date is the actual date of submittal of a verified model to the Transmission Planner for the most recently performed unit verification. • The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard. NOTE 3: Consideration for early compliance: Existing turbine/governor and load control or active power/frequency control model verification is sufficient for demonstrating compliance for a 5 year period from the actual transmittal date if either of the following applies: ☐ The Generator Owner or Transmission Owner has a verified model that is compliant with the applicable regional policies, guidelines or criteria existing at the time of model verification • The Generator Owner or Transmission Owner has an existing verified model that is compliant with the requirements of this standard NOTE 4: Net Capacity Factor Equations: Equation 1: $NCF = \frac{Net\ Actual\ Generation}{PH * NMC} * 100\%$ Equation 2: $NCF = \frac{\sum(Net\ Actual\ Generation)}{\sum(PH * NMC)} * 100\%$ Where: ☐ PH = Period Hours (Number of hours in the period being reported that the unit was in the active state) ☐ NMC = Net Maximum Capacity ☐ Equation 2 is an energy-weighted equation. Use Equation 2 when calculating for a group of units (or a unit that has a varying capacity value over time), do not simply average these factors. Follow Equation 2		

Alaska Railbelt Standard AKMOD-028-- Total Transfer Capability

A. Introduction

Title: Total Transfer Capability

Number: AKMOD-028

Purpose: To ensure that determinations of transmission system capability are completed in a manner that supports the reliable operation of the Bulk-Power System (BPS) and that the methodology and data underlying those determinations are disclosed to those registered entities that need such information for reliability purposes.

Applicability:

- R6.5.** Transmission Planner
- R6.6.** Transmission Operator
- R6.7.** Transmission Service Provider

Effective Date:

Immediately after approval of applicable regulatory authorities.

B. Requirements

- R1.** Each Transmission Planner shall develop a written methodology (or methodologies) for determining Total Transfer Capability (TTC) or Emergency Transfer Capability (ETC) values. The methodology (or methodologies) shall reflect the Transmission Operator's current practices.
 - R1.1.** Each methodology shall describe the method used to account for the following limitations in both the pre- and post-contingency state:
 - R1.1.1.** Facility ratings;
 - R1.1.2.** System voltage limits;
 - R1.1.3.** Transient stability limits;
 - R1.1.4.** Path Thermal Limits;
 - R1.1.5.** Voltage stability limits; and
 - R1.2.** Each methodology shall describe the method used to account for each of the following elements, provided such elements impact the determination of TTC or ETC:
 - R1.2.1.** The simulation of transfers performed through the adjustment of generation, load, or both;
 - R1.2.2.** Transmission topology, including, but not limited to, additions and retirements;
 - R1.2.3.** Planned outages;
 - R1.2.4.** Generator commitment;
 - R1.2.5.** Parallel path (loop flow) adjustments;

- R1.2.6.** Transmission Reliability Margin;
 - R1.2.7.** Contingency Reserve obligations of source area;
 - R1.2.8.** Load forecast; and
 - R1.2.9.** Generator dispatch, including, but not limited to, additions and retirements.
- R2.** When calculating TTCs and ETCs, the Transmission Planner shall use a Transmission model which satisfies the following requirements:
- R2.1.** The model utilizes data and assumptions consistent with the time period being studied and that meets the following criteria:
 - R2.1.1.** Includes all transmission lines and facilities rated at 69 kV and higher.
 - R2.1.2.** Models all system Elements as in-service for the assumed initial conditions.
 - R2.1.3.** Models all generation (may be either a single generator or multiple generators) that is greater than 5 MVA at the point of interconnection in the studied area.
 - R2.1.4.** Models phase shifters in non-regulating mode, unless otherwise specified in the Total Transfer Capability Implementation Document (TTCID).
 - R2.1.5.** Uses Load forecast by Balancing Authority.
 - R2.1.6.** Uses Transmission Facility additions and retirements.
 - R2.1.7.** Uses Generation Facility additions and retirements.
 - R2.1.8.** Uses Special Protection System (SPS) models where currently existing or projected for implementation within the studied time horizon unless specified otherwise in the TTCID.
 - R2.1.9.** Models series compensation for each line at the expected operating level unless specified otherwise in the TTCID.
 - R2.1.10.** Includes any other modeling requirements or criteria specified in the TTCID.
 - R2.2.** Uses Facility Ratings as provided by the Transmission Owner and Generator Owner
- R3.** The Transmission Planner shall use the following process to determine TTC and ETC:
- R3.1.** Except where otherwise specified within AKMOD-028, adjust base case generation and load levels within the updated power flow model to determine the TTC (maximum flow or reliability limit) that can be simulated on the path while at the same time satisfying all planning criteria contingencies as follows:
 - R3.1.1.** When modeling normal and contingency conditions, the projected generation commitment for the study time period shall be used.

- R3.1.2.** When modeling normal conditions, all transmission Elements will be modeled at or below 100% of their continuous rating.
- R3.1.3.** When modeling contingencies, the system shall demonstrate transient, dynamic and voltage stability, with no transmission Element modeled above its Emergency Rating following the contingency.
 - R3.1.3.1.** The modeled contingencies shall include N-1 outages of generating units and transmission lines.
 - R3.1.3.2.** The Steady-State Transfer Limit shall be identified.
 - R3.1.3.3.** The Steady-State Transfer Capability shall be identified.
 - R3.1.3.4.** The Transient Transfer Limit shall be identified.
- R3.1.4.** Uncontrolled separation shall not occur.
 - R3.1.4.1.** Separation is allowed for outages of a tie to a radial system or a tie between areas connected by one transmission Element.
- R3.2.** For a path whose capacity is limited by contract, set TTC on the path at the lesser of the maximum allowable contract capacity or the reliability limit as determined by R3.1.
- R3.3.** For a path whose TTC varies due to simultaneous interaction with one or more other paths, develop a nomogram or chart describing the interaction of the paths and the resulting TTC under specified conditions.
- R3.4.** The Transmission Planner shall identify when the TTC for the path being studied has an adverse impact on the TTC value of any existing path. Do this by modeling the flow on the path being studied at its proposed new TTC level simultaneous with the flow on the existing path at its TTC level while at the same time honoring the reliability criteria outlined in R3.1. The Transmission Planner shall include the resolution of this adverse impact in its study report.
- R3.5.** Create a study report that describes the steps above that were undertaken (R3.1 – R3.4), including the contingencies and assumptions used, when determining the TTC and the results of the study.
- R4.** The Transmission Operator shall operate the system such that each path is at or below its respective TTC.
 - R4.1.** In normal operating conditions all paths shall be operated below the minimum of:
 - R4.1.1.** Facility ratings
 - R4.1.2.** System voltage limit
 - R4.1.3.** Transient stability limit
 - R4.1.4.** Path thermal limit
 - R4.1.5.** Voltage stability limit

R4.2. Paths that are stability limited may be operated above the TTC in an Emergency.

R4.2.1. The Emergency Transfer Capability is the minimum of:

R4.2.1.1. ETC limited by Facility ratings

R4.2.1.2. ETC limited by System voltage limit

R4.2.1.3. ETC limited by Path thermal limit

R4.2.2. The path must be restored below its TTC limit in accordance with the contingency reserve restoration period defined in AKBAL-002.

R5. Within seven calendar days of the finalization of the study report, the Transmission Planner shall make available to the Transmission Operator and Transmission Service Provider of the path, the most current value for TTC and the TTC study report documenting the assumptions used and steps taken in determining the current value for TTC for that path.

R6. Within 45 calendar days of receiving a written request that references this specific requirement from a Planning Coordinator, Reliability Coordinator, Transmission Operator, Transmission Planner, Transmission Service Provider, or any other registered entity that demonstrates a reliability need, each Transmission Planner shall provide:

R6.1. A written response to any request for clarification of its TTC methodology. If the request for clarification is contrary to the Transmission Planner's confidentiality, regulatory, or security requirements then a written response shall be provided explaining the clarifications not provided, on what basis and whether there are any options for resolving any of the confidentiality, regulatory, or security concerns.

R6.2. The TTC methodology.

C. Measures

M1. Each Transmission Planner that determines TTC shall provide its current written methodology (or methodologies) or other evidence (such as written documentation) to show that its methodology (or methodologies) contains the following:

- A description of the method used to account for the limits specified in R1.1. Methods of accounting for these limits may include, but are not limited to, one or more of the following:
 - TTC being determined by one or more limits.
 - Simulation being used to find the maximum TTC that remains within the limit.
 - Monitoring a subset of limits and a statement that those limits are expected to produce the most severe results.

- A statement that the monitoring of a select limit(s) results in the TTC not exceeding another set of limits.
- A statement that one or more of those limits are not applicable to the TTC determination.
- A description of the method used to account for the elements specified in R1.2, provided such elements impact the determination of TTC. Methods of accounting for these elements may include, but are not limited to, one or more of the following:
 - A statement that the element is not accounted for since it does not affect the determination of TTC.
 - A description of how the element is used in the determination of TTC.
- Each Transmission Planner that determines TTC shall provide evidence that currently active TTC values were determined based on its current written methodology, as specified in Requirement R1.
- M2.** Each Transmission Planner shall produce any Transmission model it used to calculate TTC, as required in R2, for the time horizon(s) to be examined. (R2)
 - M2.1.** The Transmission model produced must include all system elements rated 69 kV and higher. (R2.1)
 - M2.2.** The Transmission model produced must show the use of the modeling parameters stated in R2.1.2 through R2.1.10; except that, no evidence shall be required to prove: 1) utilization of a Special Protection System where none was included in the model or 2) that no additions or retirements to the generation or Transmission system occurred. (R2.1.2 through R2.1.10)
 - M2.3.** The Transmission Planner must provide evidence that the models used to determine TTC included Facility Ratings as provided by the Transmission Owner and Generator Owner. (R2.2)
- M3.** Each Transmission Planner shall produce the TTCID it uses to show where it has described and used additional modeling criteria in its TTCID that are not otherwise included in AKMOD-28 (R2.1.4, R2.1.9, and R2.1.10).
- M4.** Each Transmission Planner shall produce as evidence the study reports, as required in R3.5, for each path for which it determined TTC for the period examined. (R3)
- M5.** Each Transmission Operator shall provide evidence that it operated the system within the TTC or ETC, when appropriate, provided by the Transmission Planner. The evidence shall include, at a minimum, any and all instances when a path exceeded its TTC during normal operations or any and all instances when a path exceed its Emergency Transfer Capability. (R4)
- M6.** Each Transmission Planner shall provide evidence (such as logs or data) that it provided the TTC and its study report to the Transmission Service Provider within seven calendar days of the finalization of the study report. (R5)
- M7.** Examples of evidence required in R6 include, but are not limited to:
 - Dated records of the request and the Transmission Planner's response to the request;

- A statement by the Transmission Planner that they have received no requests; or
- A statement by the Transmission Planner that they do not determine TTC.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. **Compliance Monitoring Period and Reset Time Frame**

Not applicable.

1.3. Data Retention

The following evidence retention periods identify the period of time a registered entity is required to retain specific evidence to demonstrate compliance. For instances in which the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask the registered entity to provide other evidence to show that it was compliant for the full time period since the last audit.

- Implementation and methodology documents shall be retained for five years.
 - Components of the calculations and the results of such calculations for all values contained in the implementation and methodology documents.
 - If a Transmission Planner is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved.
 - The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.
- The Transmission Planner shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:
 - The Transmission Planner shall have its latest models used to determine TTC for R2. (M2)
 - The Transmission Operator shall retain documentation that it operated the system within the TTC and Emergency Transfer Capability. (M4)
 - The Transmission Operator shall retain the latest version and prior version of the TTC study reports to show compliance with R3. (M5)
 - The Transmission Operator shall retain evidence for the most recent three calendar years plus the current year to show compliance with R4. (M6)

- If a Transmission Planner or Transmission Operator is found noncompliant, it shall keep information related to the non-compliance until found compliant.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.4. Compliance Monitoring and Enforcement Processes:

The following processes may be used:

- Compliance Audits
- Self-Certifications
- Spot Checking
- Compliance Violation Investigations
- Self-Reporting
- Complaints

1.5. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Levels of Non-Compliance for Requirement R1, Measure M1

- 2.1.1. Level 1** – The methodology did not reflect the Transmission Operator’s current practices.
- 2.1.2. Level 1** – The methodology failed to describe the method used to account for an element in R1.2.1 through R1.2.6.
- 2.1.3. Level 2** – The methodology failed to describe the method used to account for an element in R1.1.1 through R1.1.4.
- 2.1.4. Level 2** – Transmission Operator failed to develop a written methodology for determining TTC values.

2.2. Levels of Non-Compliance for Requirement R2, Measures M2, M3

- 2.2.1. Level 1** – The model used for calculating TTCs failed to account for up to two of the criteria specified in R2.1.1 through R2.1.10.
- 2.2.2. Level 2** – The model used for calculating TTCs failed to account for more than two of the criteria specified in R2.1.1 through R2.1.10.
- 2.2.3. Level 2** – The TP failed to produce a TTCID.

2.3. Levels of Non-Compliance for Requirement R3, Measure M4

- 2.3.1. Level 1** – The study report did not account for one of the planning criterion listed in R3.1.1 through R3.1.4.
- 2.3.2. Level 1** – Either the study report did not account for: contractual limitations, simultaneous interactions with one or more other paths, or

the study report did not account for adverse impacts on the TTC of any existing path.

2.3.3. Level 2 – A study report was not created to support TTC values.

2.4. Levels of Non-Compliance for Requirement R4, Measure M5

2.4.1. Level 1 – The TO failed to provide evidence that it operated the system within the TTC provided by the Transmission Planner.

2.4.2. Level 2 – The TO failed to take corrective action to reduce path flow below its TTC or Emergency Transfer Capability.

2.5. Levels of Non-Compliance for Requirement R5, Measure M6

2.5.1. Level 1 – The TP failed to make the most current TTC and TTC study report available to the TO and TSP for the path within 7 days of the report finalization.

2.6. Levels of Non-Compliance for Requirement R6, Measure M7

2.6.1. Level 1 – The TP failed to provide an acceptable response to a written request from a registered entity within 45 days.

Version History

Version	Date	Action	Change Tracking
1	9-16-2016	EPS - Initial Release	-
2	11-18-2016	EPS - Revisions following 10/20/2016 Meeting	Yes
3	12-06-2016	EPS - Revisions following 12/05/2016 Meeting	Yes
Final	12-06-2016	Final Version	no

AKMOD-028 Attachment 1

Sample Total Transfer Capability Implementation Document (TTCID)

This document should serve as a guideline when the Alaska Railbelt transmission planners create a TTCID as required in AKMOD-028.

Transmission Planner's Total Transfer Capability Methodology and Implementation Document

Base Case Creation

The Transmission Planner will use regionally approved planning base cases as the starting point for the study. The base cases will include the winter peak, summer peak, and summer valley load conditions. Additional cases with different load levels are recommended to identify the full range of path transfer capabilities for a wide range of operating conditions.

It is assumed that the modeling requirements listed in AKMOD-028 R2.1.1 through R2.1.5, R2.1.8, R2.1.9, and R2.2 are confirmed as part of the base case approval process. Alaska does not have phase shifting transformers and is exempt from AKMOD R2.1.4. To comply with AKMOD-028 R1.2.2 and R1.2.9 for cases focused on future time frames, the TP should confirm transmission and generation additions and retirements are modeled in the database.

The transmission planner will verify that all transmission Elements are modeled at or below 100% of their continuous rating per R3.1.2 in the base cases.

For operational studies that are studying the impact of a planned outage, remove the element from service for all base cases. If the planned outage is a generator, update the case using a commitment order as provided by the applicable BA. If the planned outage is a transmission line, remove the line from service and confirm the power flow case solves and identify if the change in system losses or transfers requires re-dispatch or re-commitment.

Power Flow Analysis

Power flow analysis (contingency analysis) shall be performed on the base cases. The contingency list should include all N-1 line contingencies rated at 69 kV and higher plus the largest generation contingency for each BA at a minimum. Confirm that at the post-contingency condition all transmission Elements remain below their emergency ratings, and all buses rated at 69 kV or higher shall have voltages that are between 0.95 and 1.05 per-unit voltage.

The generation dispatch and commitment will be adjusted to increase transfers across the path(s) that are the focus of the analysis. The following steps will be used to increase the transfers:

1. Increase source area generation and decrease sink area generation in 5 MW increments.
 - a. The next generating unit in the commitment order should be committed if the source area would have insufficient capacity to meet local demand, to source generation through the path, and to provide the required contingency reserves.
 - b. The lowest generating unit in the commitment order should be de-committed if the sink area has sufficient capacity to meet local demand and to provide the required contingency reserves.
 - c. The Transmission Planner shall use the commitment order provided by each BA

- i. Each BA shall provide a commitment and dispatch philosophy if a commitment order is not provided.
2. Run power flow analysis
 - a. Confirm that at the post-contingency condition all transmission Elements remain below their emergency ratings, and all buses rated at 69 kV or higher shall have voltages that are between 0.95 and 1.05 per-unit voltage. If post-contingency conditions meet requirements in 2.a, return to step 1.
 - b. If the flow on the transmission exceeds the emergency rating or a bus voltage is greater than 5% off its nominal voltage rating,
 - i. Revert to the case with 5 MW less transfer and record the path's Steady-State Transfer Limit, record the generation commitment and dispatch of the source and sink areas, and save the pre-contingency case.
3. Repeat steps 1 and 2 for each of the following conditions to satisfy R1.2.4
 - a. Each generation commitment of interest
 - b. If not already included in 3.a, the source area has its largest committed generation unit out of service for maintenance
 - i. Recommit generation to replace the lost capacity
 - c. If not already included in 3.a, the sink area has its largest committed generation unit out of service for maintenance
 - i. Recommit generation to replace the lost capacity

The Emergency Transfer Capability shall be set equal to the Steady-State Transfer Limit identified above. The following process will be used to identify the Steady-State Transfer Capability.

1. Subtract the source areas Contingency Reserve obligation for the largest single contingency outside the source area per AKBAL-002 R3.
2. Subtract Transmission Reliability Margin from result of 1. TRM is set to 5 MW unless specified by RRO.
3. The resulting number is the Steady-State Transfer Capability.

Additional sensitivity cases should be created to analyze if the Steady-State Transfer Limit for the path in question (primary) varies due to simultaneous interaction with one or more other paths (secondary). If feasible, the generation commitment and dispatch should be adjusted so that the flow on the primary path is near its Steady-State Transfer Limit and the secondary path is near its Steady-State Transfer Limit.

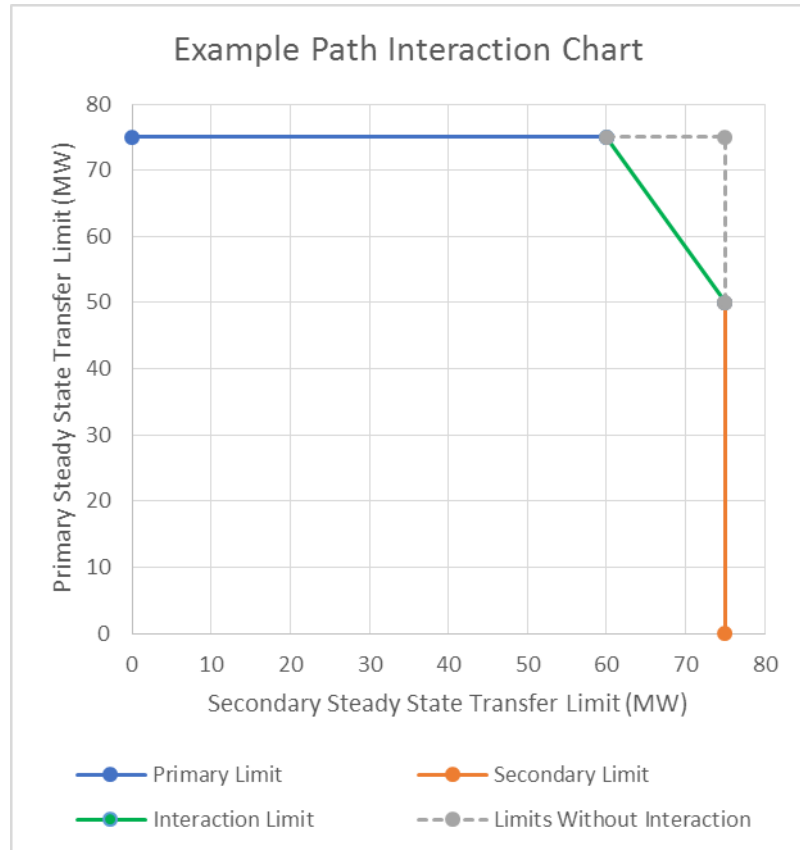
If it is not feasible to create a case with both primary and secondary paths near their Steady-State Transfer Limits, document why it is not feasible.

Run the power flow analysis described above to determine if the planning criteria is violated with both primary and secondary paths at their Steady-State Transfer Limits (or reduced limits if not feasible). If the cases satisfy the pre- and post-contingency planning criteria, no further analysis is needed because the path flows do not have simultaneous interaction. Neither

nomogram nor chart is required. The sensitivity analysis will be performed as described below if the paths do have simultaneous interactions.

Path interactions and nomogram/chart data generation

1. Use the case with the primary path at its Steady-State Transfer Limit and the secondary path at its Steady-State Transfer Limit, if feasible.
2. Reduce flow on the secondary path until the case meets the pre- and post-contingency planning criteria.
 - a. Record both primary and secondary path limits.
 - b. Save power flow case
3. Starting with the case used in step 1, reduce flow on the primary path until the case meets the pre- and post-contingency planning criteria.
 - a. Record both primary and secondary path limits.
 - b. Save power flow case
4. Create nomogram or chart using data generated in steps 1 through 3.
 - a. An example is shown below with primary and secondary Steady-State Transfer Limits of 75 MW
 - b. The secondary path can be loaded to 50 MW with the primary path at its Steady-State Transfer Limit
 - c. The primary path can be loaded to 60 MW with the secondary path at its Steady-State Transfer Limit



Dynamic Stability Analysis

The initial transient stability simulations should include an exhaustive list of N-1 contingencies. Future studies can use a subset of the most severe contingencies to reduce analysis burden. The analysis should progress in the following order.

1. Start with the power flow cases saved in the power flow analysis study including:
 - a. Cases with primary path at its Steady-State Transfer Capability with secondary paths at nominal flows,
 - b. Cases with largest generator in source and sink areas out of service.
 - c. Sensitivity cases saved as part of the path interaction and nomogram/chart data generation.
2. Simulate all contingencies in the contingency list.
3. Confirm that the case is stable, well-damped, does not suffer uncontrolled separation, and that the voltages recover to near nominal.
 - a. If all contingencies meet the requirements in step 3, the Transient Transfer Limit is larger than the Steady-State Transfer Capability and no more work is necessary.
 - b. If one or more contingencies does not meet the requirements in step 3, reduce the transfers in the same manner as was used to increase the transfers in the power flow analysis.

- i. Repeat step 2 until all contingencies result in a stable condition.
- ii. Record the Stability Limit at which all simulations were stable.
- iii. Set the Transient Transfer Limit equal to the Stability Limit minus the Transmission Reliability Margin.

The TTC will be recorded as follows:

1. For paths that have simultaneous interactions with other paths,
 - a. A nomogram or chart will describe the TTC of both the primary path and the secondary path.
 - b. Set the TTC nomogram/chart equal to the minimum of the Transient Transfer Limit and Steady-State Transfer Capability.
 - c. Set the ETC nomogram/chart equal to the Steady-State Transfer Limits.
2. For paths that do not have simultaneous interactions with other plants,
 - a. The TTC will be the minimum of the Steady-State Transfer Capability and the Transient Transfer Limit.
 - b. Set the ETC equal to the Steady-State Transfer Limit.

Study Report

Create a TTC study report documenting the assumptions used and steps taken in determining the current value for TTC and ETC for that path. Within one week of finalization, the report should be provided to the Transmission Operator.

Alaska Railbelt Standard AKMOD-032-1- Data for Power System Modeling and Analysis

A. Introduction

Title: Data for Power System Modeling and Analysis

Number: AKMOD-032-1

Purpose: To establish consistent modeling data requirements and reporting procedures for development of planning horizon cases necessary to support analysis of the reliability of the interconnected transmission system.

Applicability:

R6.3. Functional Entities:

- R6.3.1.** Balancing Authority
- R6.3.2.** Generator Owner
- R6.3.3.** Load Serving Entity
- R6.3.4.** Planning Coordinator
- R6.3.5.** Resource Planner
- R6.3.6.** Transmission Owner
- R6.3.7.** Transmission Planner
- R6.3.8.** Transmission Service Provider

Effective Date:

TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

B. Requirements

- R1.** The IMC, in conjunction with each areas' Transmission Planner, shall develop steady-state, dynamics, and short circuit modeling data requirements and reporting procedures for the Planning Coordinator's planning area that include:
 - R1.1.** The data listed in Attachment 1.
 - R1.2.** Specifications of the following items consistent with procedures for building the Interconnection-wide case(s):
 - R1.1.1.** Data format;
 - R1.1.2.** Level of detail to which equipment shall be modeled;
 - R1.1.3.** Case types or scenarios to be modeled; and
 - R1.1.4.** A schedule for submission of data at least once every 13 calendar months.
 - R1.3.** Specifications for distribution or posting of the data requirements and reporting procedures so that they are available to those entities responsible for providing the data.

- R2.** Each Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, and Transmission Service Provider shall provide steady-state, dynamics, and short circuit modeling data to any Transmission Planner(s) and Planning Coordinator(s) according to the data requirements and reporting procedures developed by its Planning Coordinator and Transmission Planner in Requirement R1. For data that has not changed since the last submission, a written confirmation that the data has not changed is sufficient.
- R3.** Upon receipt of written notification from the IMC regarding technical concerns with the data submitted under Requirement R2, including the technical basis or reason for the technical concerns, each notified Balancing Authority, Generator Owner, Load Serving Entity, Resource Planner, Transmission Owner, or Transmission Service Provider shall respond to the Regional Coordinating Council as follows:
- R3.1.** Provide either updated data or an explanation with a technical basis for maintaining the current data;
- R3.2.** Provide the response within 90 calendar days of receipt, unless a longer time period is agreed upon by the notifying the IMC.
- R4.** Each Planning Coordinator shall make available models for its planning area reflecting data provided to it under Requirement R2 to the IMC or its designee to support creation of the Interconnection-wide case(s) that includes the Planning Coordinator's planning area.

C. Measures

- M1.** The IMC shall provide evidence that it has jointly developed the required modeling data requirements and reporting procedures specified in Requirement R1.
- M2.** Each registered entity identified in Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted the required modeling data to the IMC; or written confirmation that the data has not changed.
- M3.** Each registered entity identified in Requirement R3 that has received written notification from the IMC regarding technical concerns with the data submitted under Requirement R2 shall provide evidence, such as email records or postal receipts showing recipient and date, that it has provided either updated data or an explanation with a technical basis for maintaining the current data to the IMC within 90 calendar days of receipt (or within the longer time period agreed upon by the notifying the IMC).
- M4.** Each Planning Coordinator shall provide evidence, such as email records or postal receipts showing recipient and date, that it has submitted models for its planning area reflecting data provided to it under Requirement R2 when requested by the IMC or its designee.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. Data Retention

The following data retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R4, and Measures M1 through M4, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Refer to the NERC Rules of Procedure for a list of compliance monitoring and assessment processes.

1.4. Additional Compliance Information

None

Version History

Version	Date	Action	Change Tracking
0	-	NERC Version	-
1	8-24-2016	EPS - Initial Edits	Yes
2	9-16-2016	EPS - Revisions following 8/25/2016 Meeting	Yes
3	11-18-2016	EPS - Revisions following 10/20/2016 Meeting	Yes
4	12-06-2016	EPS - Revisions following 12/05/2016 Meeting	Yes
Final	12-06-2016	Final Version	no

MOD-032-01 – ATTACHMENT 1:

Data Reporting Requirements

The table, below, indicates the information that is required to effectively model the interconnected transmission system for the Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon. Data must be shareable on an interconnection-wide basis to support use in the Interconnection-wide cases. A Planning Coordinator may specify additional information that includes specific information required for each item in the table below. Each functional entity¹ responsible for reporting the respective data in the table is identified by brackets “[functional entity]” adjacent to and following each data item. The data reported shall be as identified by the bus number, name, and/or identifier that is assigned in conjunction with the PC, TO, or TP.

steady-state	dynamics	short circuit
(Items marked with an * indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)	(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, a list of all state variables, and source code of the model, if available)	
1 Each bus [TO]	1 Generator [GO, RP (for future planned resources only)]	1 Provide for all applicable elements in column “steady-state” [GO, RP, TO]
a. nominal voltage		a. Positive Sequence Data
b. area, zone and owner	2 Excitation System [GO, RP (for future planned resources only)]	b. Negative Sequence Data
2 Aggregate Demand ² [LSE]	3 Governor [GO, RP (for future planned resources only)]	c. Zero Sequence Data
a. real and reactive power*		2 Mutual Line Impedance Data [TO]
b. in-service status*	a. real power capabilities - seasonal (summer valley, summer peak, and winter peak) maximum and minimum values	3 Fault current contribution from non-synchronous (inverter, power electronics, etc) generation sources
3 Generating Units ³ [GO, RP (for future planned resources only)]	4 Power System Stabilizer [GO, RP (for future planned resources only)]	Other information requested by the Planning Coordinator or Transmission Planner necessary for modeling
a. real power capabilities - seasonal (summer valley, summer peak, and winter peak) maximum and minimum values	5 Demand [LSE]	
b. reactive power capabilities - maximum and minimum values at real power capabilities in 3a above	a. Frequency dependence settings and documentation supporting the use of frequency dependent demand	
c. station service auxiliary load for normal plant configuration (provide data in the same manner as that required for aggregate Demand under item 2, above).	7 Photovoltaic systems [GO]	
d. regulated bus* and voltage set point* (as typically provided by the TOP)	6 Wind Turbine Data [GO]	
e. machine MVA base	7 Photovoltaic systems [GO]	
f. generator step up transformer data (provide same data as that required for transformer under item 6, below)		
g. generator type (hydro, wind, fossil, solar, nuclear, etc)		
h. in-service status*		

steady-state		dynamics		short circuit	
(Items marked with an * indicate data that vary with system operating state or conditions. Those items may have different data provided for different modeling scenarios)		(If a user-written model(s) is submitted in place of a generic or library model, it must include the characteristics of the model, including block diagrams, values and names for all model parameters, a list of all state variables, and source code of the model, if available)			
4	AC Transmission Line or Circuit [TO]	8	Energy Storage Systems [GO]		
	a. impedance parameters (positive sequence)		a. Frequency response characteristics		
	b. susceptance (line charging)		b. Contingency response characteristics		
	c. seasonal ratings (summer valley, summer peak, winter peak)*		c. Ability to simulate all modes of actual ESS operation		
	d. in-service status*				
5	DC Transmission systems [TO]	9	Static Var Systems and FACTS [GO, TO, LSE]		
6	Transformer (voltage and phase-shifting) [TO]	10	DC system models [TO]		
	a. nominal voltages of windings	11	Unit Protection Settings		
	b. impedance(s)		a. Voltage Ride Through Settings		
	c. tap ratios (voltage or phase angle)*		b. Frequency Ride Through Settings, as determined by PRC-006		
	d. minimum and maximum tap position limits				
	e. number of tap positions (for both the ULTC and NLTC)	12	Special Protection Systems		
	f. regulated bus (for voltage regulating transformers)*		Other information requested by the Planning Coordinator or		
	g. maximum seasonal (summer valley, summer peak, and winter peak) rating*	13	Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]		
	h. in-service status*				
7	Reactive compensation (shunt capacitors and reactors) [TO]				
	a. admittances (MVars) of each capacitor and reactor step				
	b. regulated voltage band limits* (if mode of operation not fixed)				
	c. mode of operation (fixed, discrete, continuous, etc.)				
	d. regulated bus* (if mode of operation not fixed)				
	e. in-service status*				
8	Static Var Systems [TO]				
	a. reactive limits				
	b. voltage set point*				
	c. fixed/switched shunt, if applicable				
	d. in-service status*				
	Other information requested by the Planning Coordinator or				
9	Transmission Planner necessary for modeling purposes. [BA, GO, LSE, TO, TSP]				

¹ For purposes of this attachment, the functional entity references are represented by abbreviations as follows: Balancing Authority (BA), Generator Owner (GO), Load Serving Entity (LSE), Planning Coordinator (PC), Resource Planner (RP), Transmission Owner (TO), Transmission Planner (TP), and Transmission Service Provider (TSP).

² For purposes of this item, aggregate Demand is the Demand aggregated at each bus under item 1 that is identified by a Transmission Owner as a load serving bus. A Load Serving Entity is responsible for providing this information, generally through coordination with the Transmission Owner.

³ Including synchronous condensers, and pumped storage, and energy storage systems.

Alaska Railbelt Standard AKMOD-33-1-Steady-State and Dynamic System Model Validation

A. Introduction

Title: Steady-State and Dynamic System Model Validation

Number: AKMOD-033-1

Purpose: To establish consistent validation requirements to facilitate the collection of accurate data and building of planning models to analyze the reliability of the interconnected transmission system.

Applicability:

R6.4. Functional Entities:

R6.4.1. Planning Coordinator

R6.4.2. Reliability Coordinator

R6.4.3. Transmission Operator

Effective Date:

AKMOD-033-1 shall become effective on the first day of the first calendar quarter that is 12 months after the date that the standard is approved by an applicable authority.

Background:

AKMOD-033-1 exists in conjunction with AKMOD-032-1, both of which are related to system-level modeling and validation. Reliability Standard AKMOD-033-1 is a new standard, and requires the IMC to implement a documented process to perform model validation for power flow and dynamics.

B. Requirements

R1. The IMC shall implement a documented data validation process that includes the following attributes:

R1.1. Comparison of the performance of the existing system in a planning power flow model simulation compared to actual system behavior, represented by a state estimator case or other Real-time data sources, for at least the summer minimum, summer and winter maximum peak conditions, at least once every 24 calendar months;

R1.2. Comparison of the performance of the existing system in a planning dynamic model to actual system response, through simulation of a dynamic event, at least once every 24 calendar months (use a dynamic event that occurs within 24 calendar months of the last dynamic event used in comparison, and complete each comparison within 24 calendar months of the dynamic event). If no dynamic event occurs within the 24 calendar months, use the next dynamic event that occurs;

R1.2.1. Performance comparison simulations should include a generation trip and a transmission line fault, at a minimum.

R1.2.1.1. By specifying these duties of the IMC, it is the intent of the standard that until such a time that the Railbelt becomes more closely interconnected, that such verifications will be completed using a generation trip and a transmission line fault in each of the three major load/generation areas.

R1.2.2. The dynamic event chosen must be able to be simulated with reasonable accuracy. Recordings and accurate description of the sequence of the event (power output of a unit that is tripped, or line from unit / plant, line flow of the line that was tripped, etc) must be available to accurately complete the comparison. Dynamic events that are a result of discreet action (unit breaker, line breaker) should be given priority over other events. Events such as unbalanced faults, unexplained unit / plant output reductions, and other obscure events should not be used for purposes of this comparison.

R1.3. Guidelines the IMC will use to determine unacceptable differences in performance under Part 1.1 or 1.2, and at a minimum will include the following;

R1.3.1. Bus frequency differences should not exceed 0.05 Hz at minimum frequency and 0.2 Hz at maximum frequency

R1.3.2. Machine electrical power differences should not exceed 2 MW during the transient and 1 MW after the transient has occurred (5 seconds after event), and 0.5 MW during steady state conditions (power flow).

R1.3.3. Tie line flow differences should not exceed 5 MW after the transient event has occurred (5 seconds after event), and 0.5 MW during steady state conditions (power flow).

IMC or, if formed by the Utilities, a Regional Reliability Organization. **1.2.**

Evidence Retention

The following evidence retention periods identify the period of time an entity is required to retain specific evidence to demonstrate compliance. For instances where the evidence retention period specified below is shorter than the time since the last audit, the Compliance Enforcement Authority may ask an entity to provide other evidence to show that it was compliant for the full time period since the last audit.

The applicable entity shall keep data or evidence to show compliance with Requirements R1 through R2, and Measures M1 through M2, since the last audit, unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation.

If an applicable entity is found non-compliant, it shall keep information related to the non-compliance until mitigation is complete and approved, or for the time specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Processes:

Compliance Audit

Self-Certification

Spot Checking

Compliance Investigation

Self-Reporting

Complaints

1.4. Additional Compliance Information

None

2. Levels of Non-Compliance

2.1. Levels of Non-Compliance for Requirement R1, Measure M1

2.1.1. Level 1 – The IMC documented and implemented a process to validate data but did not address one of the four required topics under Requirement R1; or the IMC did not perform simulation as required by part 1.1 within 24 calendar months but did perform the simulation within 30 calendar months; or the IMC did not perform simulation as required by part 1.2 within 24 calendar months (or the next dynamic event in cases where there is more than 24 months between events) but did perform the simulation within 30 calendar months.

2.1.2. Level 2 – The IMC did not have a validation process at all or did not document or implement any of the four required topics under Requirement R1; or The IMC did not validate its portion of the

system in the power flow model as required by part 1.1 within 36 calendar months; or The IMC did not perform simulation as required by part 1.2 within 36 calendar months (or the next dynamic event in cases where there is more than 24 months between events).

2.2. Levels of Non-Compliance for Requirement R2, Measure M2

2.2.1. Level 1 – The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting IMC within 30 calendar days of the written request, but did provide the data (or written response that it does not have the requested data) in less than or equal to 45 calendar days.

2.2.2. Level 2 – The Reliability Coordinator or Transmission Operator did not provide requested actual system behavior data (or a written response that it does not have the requested data) to a requesting IMC within 75 calendar days; or The Reliability Coordinator or Transmission Operator provided a written response that it does not have the requested data, but actually had the data.

E. Regional Variances

None

F. Interpretations

None

G. Associated Documents

None

Guidelines and Technical Basis

Requirement R1:

The requirement focuses on the results-based outcome of developing a process for and performing a validation, but does not prescribe a specific method or procedure for the validation outside of the attributes specified in the requirement. For further information on suggested validation procedures, see “Procedures for Validation of Powerflow and Dynamics Cases” produced by the NERC Model Working Group.

The specific process is left to the judgment of the Planning Coordinator, but the Planning Coordinator is required to develop and include in its process guidelines for evaluating discrepancies between actual system behavior or response and expected system performance for determining whether the discrepancies are unacceptable.

For the validation in part 1.1, the state estimator case or other Real-time data should be taken as close to desired seasonal conditions as possible. While the requirement specifies “once every 24 calendar months,” entities are encouraged to perform the comparison on a more frequent basis. Until the model has been sufficiently verified to confirm its accuracy in varying load and generation conditions, each entity is encouraged to confirm the model following each major system disturbance.

In performing the comparison required in part 1.1, the Planning Coordinator may consider, among other criteria:

1. System load;
2. Transmission topology and parameters;
3. Voltage at major buses; and
4. Flows on major transmission elements.

The validation in part 1.1 would include consideration of the load distribution and load power factors (as applicable) used in the power flow models. The validation may be made using metered load data or state estimator cases. The comparison of system load distribution and load power factors shall be made on the substation level at a minimum but may also be made on a bus by bus basis within each substation, or smaller area basis as deemed appropriate by the Planning Coordinator.

The validation required in part 1.2 may include simulations that are to be compared with actual system data and may include comparisons of:

- Voltage oscillations at major buses
- System frequency (for events with frequency excursions)
- Real and reactive power oscillations on generating units and major inter-area ties

Determining when a dynamic event might occur may be unpredictable, and because of the analytic complexities involved in simulation, the time parameters in part 1.2 specify that the comparison period of “at least once every 24 calendar months” is intended to both provide for at least 24 months between dynamic events used in the comparisons and that comparisons must be completed within 24 months of the date of the dynamic event used. This clarification ensures that PCs will not face a timing scenario that makes it impossible to comply. If the

time referred to the completion time of the comparison, it would be possible for an event to occur in month 23 since the last comparison, leaving only one month to complete the comparison. With the 30 day timeframe in Requirement R2 for TOPs or RCs to provide actual system behavior data (if necessary in the comparison), it would potentially be impossible to complete the comparison within the 24 month timeframe.

In contrast, the requirement language clarifies that the time frame between dynamic events used in the comparisons should be within 24 months of each other (or, as specified at the end of part 1.2, in the event more than 24 months passes before the next dynamic event, the comparison should use the next dynamic event that occurs). Each comparison must be completed within 24 months of the dynamic event used. In this manner, the potential problem with a “month 23” dynamic event described above is resolved. For example, if a PC uses for comparison a dynamic event occurring on day 1 of month 1, the PC has 24 calendar months from that dynamic local event’s occurrence to complete the comparison. If the next dynamic event the PC chooses for comparison occurs in month 23, the PC has 24 months from that dynamic event’s occurrence to complete the comparison.

Part 1.3 requires the PC to include guidelines in its documented validation process for determining when discrepancies in the comparison of simulation results with actual system results are unacceptable. The PC may develop the guidelines required by parts 1.3 and 1.4 itself, reference other established guidelines, or both. For the power flow comparison, as an example, this could include a guideline the Planning Coordinator will use that flows on 138 kV lines should be within 10% or 5 MW, whichever is larger. It could be different percentages or MW amounts for different voltage levels. Or, as another example, the guideline for voltage comparisons could be that it must be within 1%. But the guidelines the PC includes within its documented validation process should be meaningful for the Planning Coordinator’s system. Guidelines for the dynamic event comparison may be less precise. Regardless, the comparison should indicate that the conclusions drawn from the two results should be consistent. For example, the guideline could state that the simulation result will be plotted on the same graph as the actual system response. Then the two plots could be given a visual inspection to see if they look similar or not. Or a guideline could be defined such that the rise time of the transient response in the simulation should be within 20% of the rise time of the actual system response. As for the power flow guidelines, the dynamic comparison criteria should be meaningful for the Planning Coordinator’s system.

The guidelines the PC includes in its documented validation process to resolve differences in Part 1.4 could include direct coordination with the data owner, and, if necessary, through the provisions of AKMOD-032-1, Requirement R3 (i.e., the validation performed under this requirement could identify technical concerns with the data). In other words, while this standard is focused on validation, results of the validation may identify data provided under the modeling data standard that needs to be corrected. If a model with estimated data or a generic model is used for a generator, and the model response does not match the actual response, then the estimated data should be corrected or a more detailed model should be requested from the data provider.

If the simulations can be made to match the actual system responses by reasonable changes to the data in the Planning Coordinator’s area, then the Planning Coordinator should make those changes in coordination with the data provider. The guidelines the Planning Coordinator included under Part 1.4 could cover these situations.

Rationale for R1:

Requirement R1 requires the Planning Coordinator to implement a documented data validation process to validate data in the Planning Coordinator's portion of the existing system in the steady-state and dynamic models to compare performance against expected behavior or response. The following items were chosen for the validation requirement:

- A. Comparison of performance of the existing system in a planning power flow model to actual system behavior; and
- B. Comparison of the performance of the existing system in a planning dynamics model to actual system response.

Implementation of these validations will result in more accurate power flow and dynamic models. This, in turn, should result in better correlation between system flows and voltages seen in power flow studies and the actual values seen by system operators during outage conditions. Similar improvements should be expected for dynamics studies, such that the results will more closely match the actual responses of the power system to disturbances.

Validation of model data is a good utility practice, but it does not easily lend itself to Reliability Standards requirement language. Furthermore, it is challenging to determine specifications for thresholds of disturbances that should be validated and how they are determined. Therefore, this requirement focuses on the Planning Coordinator performing validation pursuant to its process, which must include the attributes listed in parts 1.1 through 1.4, without specifying the details of "how" it must validate, which is necessarily dependent upon facts and circumstances. Other validations are best left to guidance rather than standard requirements.

Rationale for R2:

The Planning Coordinator will need actual system behavior data in order to perform the validations required in R1. The Reliability Coordinator or Transmission Operator may have this data. Requirement R2 requires the Reliability Coordinator and Transmission Operator to supply actual system data, if it has the data, to any requesting Planning Coordinator for purposes of model validation under Requirement R1.

This could also include information the Reliability Coordinator or Transmission Operator has at a field site. For example, if a PMU or DFR is at a generator site and it is recording the disturbance, the Reliability Coordinator or Transmission Operator would typically have that data.

Version History

Version	Date	Action	Change Tracking
0	-	NERC Version	-
1	3-21-2016	EPS edit from NERC standards	Yes
2	9-16-2016	EPS - Revisions following 8/25/2016 Meeting	Yes
3	11-18-2016	EPS - Revisions following 10/20/2016 Meeting	Yes
Final	12-06-2016	Final Version	no

AKMOD-033 – Attachment 1

Example Interconnection Model Validation Process and Guidelines:

Alaska's primary concerns include loss of synchronism over the major tie lines, and the activation of UFLS in response to the loss of generation. The guidelines listed below were created for the Alaskan Railbelt. The validation sections below should serve as an example set of guidelines as required in Requirement 1.3.

Power Flow

Input Data

The following items from the recorded snapshot data are transferred directly into the steady-state power flow case (state estimators may be a suitable source for this data):

- Generators
 - Real power output
 - Reactive power output or voltage setting
 - Control mode (voltage control, power factor control)
 - Voltage regulation point (local or remote, if on voltage control)
 - Status
- Loads
 - Measured real power at available granularity
 - Measured reactive power
- Transmission Network
 - Network topology
 - Device statuses
 - Transmission lines
 - Breakers (may result in split buses)
 - Reactive shunt elements (Capacitor, Reactor)
 - Reactive series elements (Capacitor, Reactor)
 - Fixed-tap transformer tap positions
 - ULTC transformers – Fixed tap position and LTC voltage setting
 - Phase-shifting transformers – angle position or MW setting
 - Static VAR systems and fast-switched shunt devices – reactive output or voltage setting
 - DC lines – active power flow
 - Other devices present in system model
- Wide-Area Control
 - Area interchange totals

After data is inserted, a power flow solution is performed. After the initial power flow solution is performed, the following priority list should be used when comparing the power flow solution to the recorded values.

Validation

1. Minimize the tie flow error (recorded vs. simulation) between areas with a desired error of 0.5 MW or less.
 - a. The tie flows should take top priority due to the transient stability concerns.
 - b. May need to adjust recorded generation and/or area load.
2. Minimize generation error within +/- 0.5 MW.
 - a. Use recorded values to the extent possible. May need adjustment based on tie flows.
 - b. May need to adjust area load so slack generator matches the recorded MW while keeping tie flows close to recorded values.
3. Adjust voltage setpoints to match recorded voltages within +/- 1%. Minimize generation error within +/- 1.0 MVAR.
 - a. Engineering judgement should be used when balancing the voltage errors and generation reactive power errors.
4. Use recorded load MW, MVAR.
 - a. To match generation and tie flows the unobservable load should be adjusted
 - b. If necessary, the recorded load may need to be adjusted to match line flows, tie flows, and generation outputs.

If using power flow case for transient stability analysis, the relative priority above may change based on the goals of the validation case. The generation output would take highest priority if a specific unit is going to be tripped as part of the transient stability validation. Whereas, the line flow would take priority when a transmission line fault and trip will be simulated as part of the transient stability validation process.

Transient Stability

Input Data

Comparisons between simulation results from the model and measured dynamic data provide an indication of the collective validity of a large set of component dynamics models. The following data must be entered in the transient stability database, at a minimum:

- Generator
 - Status of exciter
 - Status of PSS
 - Status of governor (Droop, temperature limits, etc.)
 - Control parameters (gains, feedback time constants, etc.)
 - Machine characteristics (inertia, time constants)
- Load model
 - Real and reactive power under dynamic conditions
- Transmission Network model
 - Reactive shunt dynamics models (automatic shunt switching)
 - SVC model characteristics
- Dynamic Load Characteristics

- Dynamic load characteristic models have never been utilized with the Railbelt model. In other islanded systems, the dynamic load characteristics can have a noticeable impact on the ability of the model to replicate actual system disturbances. Transient recorders at stations that serve load should be utilized to ascertain the dynamic response of load to changes in voltage and frequency characteristics. Often times, this characteristic will vary depending upon the time of day/season of the event. Estimates of load characteristics at stations with recorders should be used as a proxy for similar loads in the system.

Validation

Non-3-phase faults are going to be more difficult to validate since industry tools are positive sequence programs.

1. Match interconnection frequency response within 0.05 Hz at minimum frequency and 0.2 Hz at maximum frequency.
 - a. In order to ensure proper margin it is preferable that the simulation response has an interconnection frequency that is slightly lower or equal to the recorded interconnection frequency response for under frequency events. Adjustments to the load characteristics may be made to get the load to match recorded load during the transient event after all other possible adjustments have been exhausted.
2. Match the recorded and simulated generation responses to within 2 MW during the transient and 1 MW after the transient has occurred (5 seconds after event).
 - a. The primary goal of the validating is to match the interconnection frequency. The simulated generation response should match the recordings but preference should be given to the interconnection frequency. Multiple iterations alternating between matching the system load characteristics and generation output may be required to obtain close correlation between the simulation and recorded values.
3. Using engineering judgement, match the significant flows between areas within 5 MW after the transient has occurred (5 seconds after event).
 - a. The stability limits along the tie from Kenai to Anchorage and from Anchorage to Fairbanks are a significant concern and dictate many operational limits. Ensuring simulations match the recorded tie-line flows will improve the confidence in the defined limits.
4. Using engineering judgement, match the recorded and simulated major bus voltages within +/-2% during pre and post-disturbance comparisons.

Alaska Railbelt Standard AKPRC-006 Automatic Underfrequency Load Shedding

A. Introduction

1. Title: Automatic Underfrequency Load Shedding

2. Number: AKPRC-006

3. Purpose:

To establish design and documentation requirements for automatic underfrequency load shedding (UFLS) programs to arrest declining frequency, assist recovery of frequency following underfrequency events and provide last resort system preservation measures.

4. Applicability:

4.1. UFLS entities shall mean all entities that are responsible for the ownership, operation, or control of UFLS equipment as required by the UFLS program established by the IMC. Such entities may include one or more of the following:

4.1.1. Planning Coordinators

4.1.2. Transmission Owners

4.1.3. Distribution Providers

5. Effective Date: TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

B. Requirements

R1. The IMC shall develop and document criteria within the Railbelt system, including consideration of historical events and system studies, to select load levels within the Distribution Provider's Area to form load shedding stages.

R1.1. The UFLS program shall be designed for the system to survive the following imbalance scenarios (at a minimum) for all system load conditions.

R1.1.1. Loss of generation or transfers as determined by the Maximum N-1 Contingency Criteria.

R1.1.2. Loss of generation or transfers as defined in AKBAL-002 as a Reportable Excess Contingency.

R1.1.3. Loss of largest plant.

R1.2. The UFLS program shall be designed with a provision for a backup block of load (s) with an extended time delay to prevent extended low frequency operation.

R1.3. The UFLS program shall be designed such that the loss of a contingency less than 75% of the Maximum N-1 Contingency Criteria should not result in the activation of the UFLS program.

R1.4. The UFLS program shall consider severe scenarios of unit commitment and dispatch defined to limit reserve response and location.

- R2.** The IMC shall design the UFLS with the requirements of the interconnected system and subsequently identify one or more islands to serve as a basis for designing its UFLS program during islanding conditions including:
- R2.1.** Any portions of the BES designed to detach from the Interconnection (planned islands) as a result of the operation of a relay scheme or Special Protection System, and
 - R2.2.** A single island that includes all portions of the BES in either the Regional Entity area or the Interconnection in which the Planning Coordinator's area resides.
 - R2.3.** The load included in the UFLS for the protection of the interconnected system shall not be included in a SILOS program. Load included in an island's UFLS system designed to protect the area following islanding may be included in a SILOS program.
- R3.** The IMC shall develop a UFLS program within the Railbelt system, including notification of and a schedule for implementation by UFLS entities within the interconnected system, that meets the following performance characteristics in simulations of underfrequency conditions resulting from an imbalance scenario, where $\text{imbalance} = [(\text{load} - \text{actual generation output}) / (\text{load})]$.
- R3.1.** Frequency shall remain within the bounds of the Underfrequency Performance Characteristic curve contained within Attachment 1, either for 60 seconds or until a steady-state condition between 59.5 Hz and 60.5 Hz is reached for any contingency less than or equal to the Maximum N-1 Contingency Criteria.
 - R3.2.** Frequency shall remain within the bounds of the Underfrequency Performance Characteristic curve contained within Attachment 1, either for 60 seconds or until a steady-state condition between 59.3 Hz and 60.7 Hz is reached for any contingency larger than the Maximum N-1 Contingency Criteria.
 - R3.3.** The UFLS program shall be designed such that no UFLS program action results in an interconnected system frequency that exceeds 61.8 Hz for any contingency.
 - R3.3.1.** Portions of the BES designed to detach from the Interconnection as a result of the operation of a relay scheme or Special Protection System may exceed these frequency limits but should not exceed 63.0 Hz following a UFLS program activation.
 - R3.4.** Simulated UFLS events shall not result in Volts per Hertz (V/Hz) exceeding the generator trip settings or equipment damage limits if no protection exists.
 - R3.5.** Simulated UFLS events shall not result in an increase in transfers between areas that exceed the transfer limits of the transmission path.
- R4.** The IMC shall conduct and document a UFLS design assessment within the Railbelt system at least once every five years or upon any significant changes in Distribution Providers' resources or characteristics of the Bulk Electric Transmission System that

may impact UFLS performance. The design assessment shall update the UFLS design as necessary to maintain the performance characteristics in Requirement R3 for each island identified in Requirement R2. The simulation shall model each of the following:

- R4.1.** Underfrequency trip settings of each generating unit / plant with a nameplate capability larger than or equal to 5 MVA directly connected to the BES through a single contingency interconnection that trips within the bounds of the Generator Underfrequency Trip Modeling curve in AKPRC-006 - Attachment 1.
- R4.2.** Overfrequency trip settings of each generating unit / plant greater than 5 MVA (gross nameplate rating) directly connected to the BES through a single contingency interconnection that trips below the Generator Overfrequency Trip Modeling curve in AKPRC-006 — Attachment 1
- R4.3.** Any system action that impacts Interconnection frequency response including:
 - R4.3.1.** Any automatic load restoration that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
 - R4.3.2.** Any operation of a relay scheme or Special Protection System that impacts frequency stabilization and operates within the duration of the simulations run for the assessment.
 - R4.3.3.** Operation of plant controls that affect unit response and system frequency.
 - R4.3.4.** The best estimate of each Distribution Provider load's response to changes in system frequency or voltage.
- R5.** Each Planning Coordinator, whose area or portions of whose area is part of an island designed to detach from the BES as a result of the operation of a relay scheme or Special Protection System shall coordinate its UFLS program with the IMC:
 - Develop a common UFLS program design and schedule for implementation per Requirement R3 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct a joint UFLS design assessment per Requirement R4 among the Planning Coordinators whose areas or portions of whose areas are part of the same identified island, or
 - Conduct an independent UFLS design assessment per Requirement R4 for the identified island, and in the event the UFLS design assessment fails to meet Requirement R3, identify modifications to the UFLS program(s) to meet Requirement R3 and report these modifications as recommendations to the other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.
- R6.** Each Planning Coordinator shall maintain a UFLS database containing data necessary to model its UFLS program for use in event analyses and assessments of the UFLS

program at least once each calendar year, with no more than 15 months between maintenance activities.

- R7.** Each Planning Coordinator shall provide its UFLS database containing data necessary to model its UFLS program to other Planning Coordinators within the Interconnection within 30 calendar days of a request.
- R8.** Each UFLS entity shall provide data to its Planning Coordinator(s) according to the format and schedule specified by the Planning Coordinator(s) to support maintenance of each Planning Coordinator's UFLS database.
- R9.** Each UFLS entity shall provide automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by its Planning Coordinator(s) in each Planning Coordinator area in which it owns assets.
- R10.** Each Transmission Owner shall provide automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application determined by the Planning Coordinator(s) in each Planning Coordinator area in which the Transmission Owner owns transmission.
- R11.** The IMC shall conduct and document an assessment for an event that results in system frequency excursions below the initializing set points of the UFLS program, within two (2) months of event to evaluate:
 - R11.1.** The performance of the UFLS equipment,
 - R11.2.** The effectiveness of the UFLS program.
 - R11.3.** If further analysis is not required, all documentation should be completed within two (2) months from the initial event.
- R12.** The IMC shall conduct and document a UFLS design assessment as outlined in R4 to evaluate the event and UFLS response, when an UFLS initial event assessment (per R11) shows need for additional analysis, within six (6) months of the event. The analysis shall include, but not be limited to:
 - R12.1.** A description of the event including initiating conditions.
 - R12.2.** A review of the UFLS set points and tripping times.
 - R12.3.** A simulation of the event.
 - R12.4.** A summary of the findings.
- R13.** The IMC shall respond to written comments submitted by UFLS entities and Transmission Owners following a comment period and before finalizing its UFLS program, indicating in the written response to comments whether changes will be made or reasons why changes will not be made to the following:
 - R13.1.** UFLS program, including a schedule for implementation
 - R13.2.** UFLS design assessment
 - R13.3.** Format and schedule of UFLS data submittal

C. Measures

- M1.** Each Planning Coordinator shall have evidence such as reports, or other documentation of its criteria to select portions of its system that may form load shedding blocks including how system studies and historical events were considered to develop the criteria per Requirement R1.
- M2.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, or other documentation supporting its identification of potential islands to serve as a basis for designing a UFLS program that meet the criteria in Requirement R2.
- M3.** Each Planning Coordinator shall have evidence such as reports, memorandums, e-mails, program plans, or other documentation of its UFLS program, including the notification of the UFLS entities of implementation schedule, that meet the criteria in Requirement R3.
- M4.** Each Planning Coordinator shall have dated evidence such as reports, dynamic simulation models and results, or other dated documentation of its UFLS design assessment that demonstrates it meets Requirement R4.
- M5.** Each Planning Coordinator, whose area or portions of whose area is part of an island identified by it or another Planning Coordinator shall have dated evidence such as joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island per Requirement R5.
- M6.** Each Planning Coordinator shall have dated evidence such as a UFLS database, data requests, data input forms, or other dated documentation to show that it maintained a UFLS database for use in event analyses and assessments of the UFLS program per Requirement R6 at least once each calendar year, with no more than 15 months between maintenance activities.
- M7.** Each Planning Coordinator shall have dated evidence such as letters, memorandums, e-mails or other dated documentation that it provided their UFLS database to other Planning Coordinators within the Interconnection within 30 calendar days of a request per Requirement R7.
- M8.** Each UFLS Entity shall have dated evidence such as responses to data requests, spreadsheets, letters or other dated documentation that it provided data to its Planning Coordinator according to the format and schedule specified by the Planning Coordinator to support maintenance of the UFLS database per Requirement R8.
- M9.** Each UFLS Entity shall have dated evidence such as spreadsheets summarizing feeder load armed with UFLS relays, spreadsheets with UFLS relay settings, or other dated documentation that it provided automatic tripping of load in accordance with the UFLS program design and schedule for application per Requirement R9.
- M10.** Each Transmission Owner shall have dated evidence such as relay settings, tripping logic or other dated documentation that it provided automatic switching of its existing capacitor banks, Transmission Lines, and reactors in order to control over-

voltage as a result of underfrequency load shedding if required by the UFLS program and schedule for application per Requirement R10.

- M11.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted an event assessment of the performance of the UFLS equipment and the effectiveness of the UFLS program per Requirement R9.
- M12.** Each Planning Coordinator shall have dated evidence such as reports, data gathered from an historical event, or other dated documentation to show that it conducted a UFLS design assessment per Requirements R12 and R4 if UFLS program deficiencies are identified in R11.
- M13.** Each Planning Coordinator shall have dated evidence of responses, such as e-mails and letters, to written comments submitted by UFLS entities and Transmission Owners within the Interconnection following a comment period and before finalizing its UFLS program per Requirement R13.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. Data Retention

Each Planning Coordinator and UFLS entity shall keep data or evidence to show compliance as identified below unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- Each Planning Coordinator shall retain the current evidence of Requirements R1, R2, R3, R4, R5, R12, and R13, Measures M1, M2, M3, M4, M5, M12, and M13 as well as any evidence necessary to show compliance since the last compliance audit.
- Each Planning Coordinator shall retain the current evidence of UFLS database update in accordance with Requirement R6, Measure M6, and evidence of the prior year's UFLS database update.
- Each Planning Coordinator shall retain evidence of any UFLS database transmittal to other Planning Coordinators in the Interconnection since the last compliance audit in accordance with Requirement R7, Measure M7.
- Each UFLS entity shall retain evidence of UFLS data transmittal to the Planning Coordinator(s) since the last compliance audit in accordance with Requirement R8, Measure M8.
- Each UFLS entity shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R9, Measure M9, and evidence of adherence since the last compliance audit.

- Transmission Owner shall retain the current evidence of adherence with the UFLS program in accordance with Requirement R10, Measure M10, and evidence of adherence since the last compliance audit.
- Each Planning Coordinator shall retain evidence of Requirements R11, and R13, and Measures M11, and M13 for 6 calendar years.

If a Planning Coordinator or UFLS entity is found non-compliant, it shall keep information related to the non-compliance until found compliant or for the retention period specified above, whichever is longer.

The Compliance Enforcement Authority shall keep the last audit records and all requested and submitted subsequent audit records.

1.3. Compliance Monitoring and Assessment Process

- Compliance Audit
- Self-Certification
- Spot Checking
- Compliance Violation Investigation
- Self-Reporting
- Complaint

1.4. Additional Compliance Information

Not applicable.

2. Levels of Non-Compliance

2.1. Levels of Non-Compliance for Requirement R1, Measure M1

- 2.1.1. Level 1** - The IMC developed and documented criteria but failed to include either the consideration of historical events or the consideration of system studies.
- 2.1.2. Level 2** - The IMC failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

2.2. Levels of Non-Compliance for Requirement R2, Measure M2

- 2.2.1. Level 1** - NA
- 2.2.2. Level 2** - The IMC failed to identify islands to serve as a basis for designing its UFLS program as specified in Requirement R2.

2.3. Levels of Non-Compliance for Requirement R3, Measure M3

- 2.3.1. Level 1** - The IMC developed a UFLS program, including a schedule for implementation within its area where imbalance = (load — actual generation output) / (load), but failed to meet one (1) of the performance characteristic in Requirement Part R3.1 through Part R3.3 in simulations of underfrequency conditions.

- 2.3.2. **Level 2** – The IMC failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.
- 2.4. **Levels of Non-Compliance for Requirement R4, Measure M4**
 - 2.4.1. **Level 1** - The IMC conducted and documented a UFLS assessment at least once every five years that determined through dynamic simulation whether the UFLS program design met the performance characteristics in Requirement R3 for each island identified in Requirement R2 but the simulation failed to include one (1) of the items as specified in Requirement Part R4.1 through Part R4.4.
 - 2.4.2. **Level 2** – The IMC failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.
- 2.5. **Levels of Non-Compliance for Requirement R5, Measure M5**
 - 2.5.1. **Level 1** – The Planning Coordinator failed to retain dated evidence of joint UFLS program design documents, reports describing a joint UFLS design assessment, letters that include recommendations, or other dated documentation demonstrating that it coordinated its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.
 - 2.5.2. **Level 2** - The Planning Coordinator failed to coordinate its UFLS program design with all other Planning Coordinators whose areas or portions of whose areas are also part of the same identified island.
- 2.6. **Levels of Non-Compliance for Requirement R6, Measure M6**
 - 2.6.1. **Level 1** – N/A
 - 2.6.2. **Level 2** - The Planning Coordinator failed to perform maintenance on the UFLS database within 15 months of previous maintenance activity.
- 2.7. **Levels of Non-Compliance for Requirement R7, Measure M7**
 - 2.7.1. **Level 1** – The Planning Coordinator provided data more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by Requirement R7 to support maintenance of the UFLS database.
 - 2.7.2. **Level 2** - The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.
- 2.8. **Levels of Non-Compliance for Requirement R8, Measure M8**
 - 2.8.1. **Level 1** - The UFLS entity provided data more than 5 calendar days but less than or equal to 10 calendar days following the schedule specified by Requirement R8 to support maintenance of the UFLS database.
 - 2.8.2. **Level 2** - The UFLS entity failed to meet all the requirements of Level 1 for Requirement R8 and Measurement M8.
- 2.9. **Levels of Non-Compliance for Requirement R9, Measure M9**

2.9.1. Level 1 - The UFLS entity provided less than 100% but more than (and including) 90% of automatic tripping of Load in accordance with the UFLS program design and schedule for application determined by the Requirement R9.

2.9.2. Level 2 - The UFLS entity failed to meet all the requirements of Level 1 for Requirement R9 and Measurement M9.

2.10. Levels of Non-Compliance for Requirement R10, Measure M10

2.10.1. Level 1 - The Transmission Owner provided less than 100% but more than (and including) 90% automatic switching of its existing capacitor banks, Transmission Lines, and reactors to control over-voltage if required by the UFLS program and schedule for application determined by Requirement R10.

2.10.2. Level 2 - The Transmission Owner failed to meet all the requirements of Level 1 for Requirement R10 and Measurement M10.

2.11. Levels of Non-Compliance for Requirement R11, Measure M11

2.11.1. Level 1 - The Planning Coordinator, in which UFLS program deficiencies were identified per Requirement R9, conducted and documented a UFLS design assessment to consider the identified deficiencies greater than six months but less than or equal to 7 months of event actuation.

2.11.2. Level 2 - The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R11 and Measurement M11.

2.12. Levels of Non-Compliance for Requirement R12, Measure M12

2.12.1. Level 1 – The Planning Coordinator, in whose area an event results in a system frequency excursion below the initializing set points of the UFLS program, conducted an assessment of the UFLS event more than one (1) month but less than two (2) months after the initiating event.

2.12.2. Level 2 - The Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R12 and Measurement M12.

2.13. Levels of Non-Compliance for Requirement R13, Measure M13

2.13.1. Level 1 – N/A

2.13.2. Level 2 – The Planning Coordinator failed to retain dated evidence of responses submitted by UFLS entities and Transmission Owners within the Interconnection.

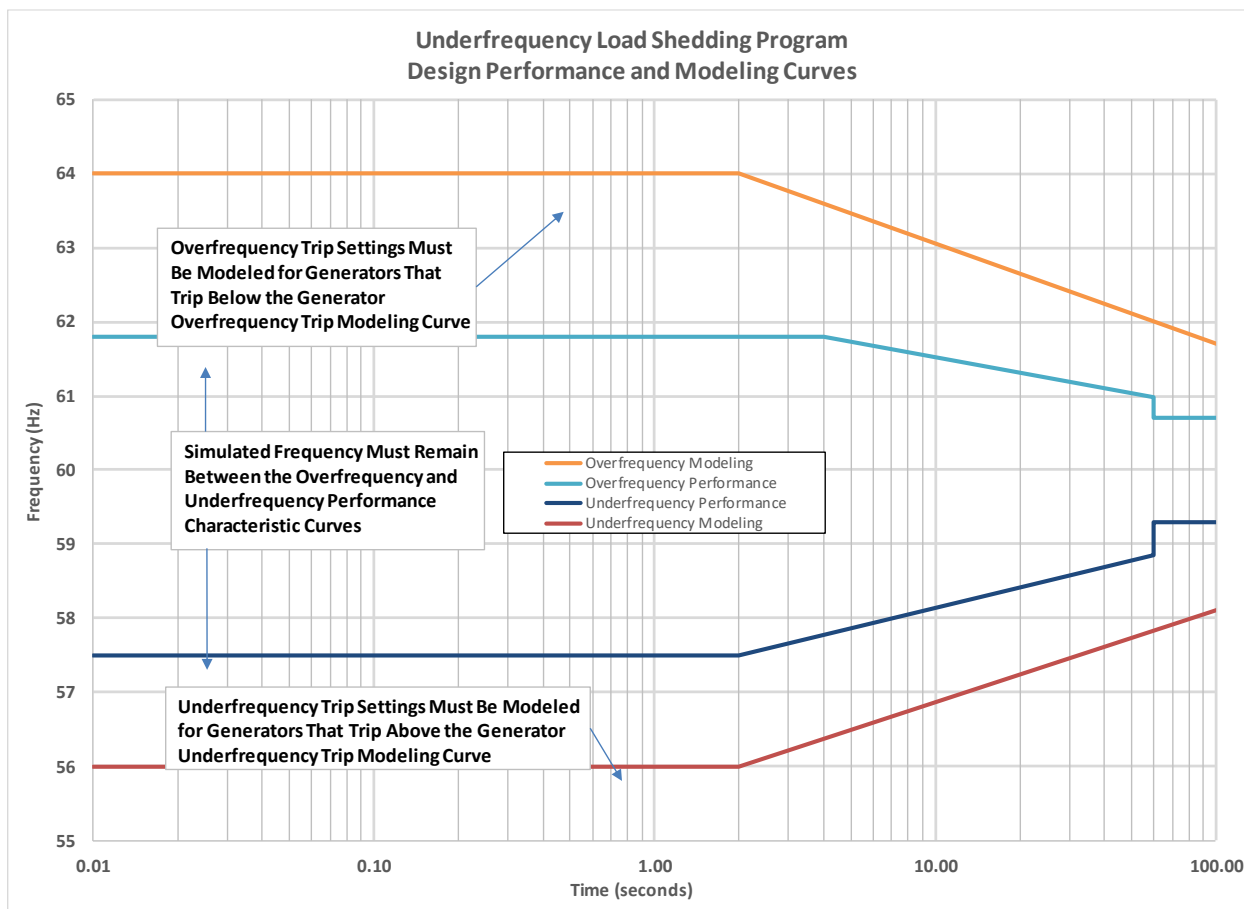
E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
0	-	Approved - IMC	-
1	11-05-2015	EPS - Initial Edits	Yes
2	12-21-2015	EPS - Revision Edits	Yes
3	1-4-2016	EPS - Revision Edits	Yes
4	1-22-2016	EPS - Revision Following 1/19 Meeting	Yes
5	2-9-2016	EPS - Revision Following 1/28 Meeting	Yes
6	2-12-2016	Final IMC Revision	No
7	11-18-2016	EPS - Inclusion of RCC	Yes
8	12-06-2016	Final	No

AKPRC-006 – Attachment 1



Generator Overfrequency Trip Modeling		Generator Overfrequency Performance Characteristic		
$t < 2 \text{ s}$	$t \geq 2 \text{ s}$	$t < 4 \text{ s}$	$60 \text{ s} > t \geq 4 \text{ s}$	$t \geq 60 \text{ s}$
$f = 64 \text{ Hz}$	$f = -0.686 \cdot \log(t) + 62.41 \text{ Hz}$	$f = 61.8 \text{ Hz}$	$f = -0.686 \cdot \log(t) + 62.21 \text{ Hz}$	$f = 60.7 \text{ Hz}$

Generator Underfrequency Trip Modeling		Generator Underfrequency Performance Characteristic		
$t < 2 \text{ s}$	$t \geq 2 \text{ s}$	$t < 2 \text{ s}$	$60 \text{ s} > t \geq 2 \text{ s}$	$t \geq 60 \text{ s}$
$f = 56 \text{ Hz}$	$f = 0.575 \cdot \log(t) + 57.63 \text{ Hz}$	$f = 57.5 \text{ Hz}$	$f = 0.915 \cdot \log(t) + 57.23 \text{ Hz}$	$f = 59.3 \text{ Hz}$

Alaska Railbelt Standard AKRES-001-1 — Reserve Obligation and Allocation

A. Introduction

1. Title: Reserve Obligation and Allocation

2. Number: AKRES-001-1

3. Purpose:

This standard describes Reserve Obligations for all Obligated Entities interconnected to the Railbelt Grid.

4. Applicability:

4.1. Balancing Authorities

4.2. Load Serving Entities

4.3. Generation Owners

5. Effective Date: 12 months from package adoption

B. Requirements

R1. Reserve Capacity Obligation Requirement

R1.1. Each Load Serving Entity (LSE) is expected to have and maintain responsibility to provide capacity for its own firm load. As part of such responsibility, the LSE shall maintain or otherwise provide for annually, Accredited Capacity, in an amount equal to or greater than its maximum System Demand for such year plus the Load Serving Entities' Reserve Capacity Obligation, as set forth in Subsection R1.2.

R1.2. The Reserve Capacity Obligation of a Load Serving Entity, for any year, shall be equal to thirty (30) percent of the Annual System Demand (described in R1.4) for that year for that Load Serving Entity. The Reserve Capacity Obligation of the Load Serving Entity may be adjusted from time to time by the IMC.

R1.3. The IMC may determine the annual Accredited Capacity for each Load Serving Entity.

R1.4. Reserve Capacity Obligation shall be determined by the one-hour average of peak electrical demand of the LSE as determined for each the average of the previous three calendar years of load data of the LSE. The LSE may petition the RRO to use a different value if their studies indicate a different value is warranted than that calculated as described above.

R2. Responsibility for Operating Reserve

R2.1. Each Load Serving Entity and/or Generation Owner shall provide, or contract for, Regulating Reserve, Spinning Reserve and Non-Spinning Reserve as required by Section R3 of this Standard equal to or greater than the Operating Reserve Obligation of the entity. As soon as practicable, but not to exceed four hours, after the occurrence of an incident which uses Operating Reserves, each entity shall restore its Operating Reserve Obligation.

R2.2. The System Reserve Basis (SRB) is equal to the declared Largest Single Generating Contingency of the system or other such value as determined by

engineering studies and approved by the IMC. The SRB is determined on an hourly basis and may include critical infrastructure whose loss would deprive the majority of the system of multiple generating units as defined in the Reserves Policy.

R3. Total Operating Reserve Obligation

- R3.1.** The Total Operating Reserve Obligation at any time shall be an amount equal to 150 percent of the System Reserve Basis of the Railbelt Grid.
- R3.2.** The Spinning Reserve portion of the Total Operating Reserve Obligation shall not be less than an amount equivalent to 100 percent of the System Reserve Basis.
- R3.3.** The regulation amount of the Operating Reserve Obligation must be an amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
- R3.4.** The balance of the Total Operating Reserve Obligation shall be maintained with Non Spinning Reserve.

R4. Generating Unit Capability

Declared generating unit capability for operating reserve shall be determined by the following criteria:

- R4.1.** It shall not be less than the load and reserves on the machine at any particular time nor greater than R4.2 below.
- R4.2.** It shall not exceed that maximum amount of load (MW) that the unit is capable of continuously supplying for a two-hour period through action of automatic governor controls. Alternatively, if the unit is not capable of continuously supplying for a two-hour period, it must be supplemented by other sources of reserves when it runs out. For example, a Battery Energy Storage System that is supplemented by a load shedding scheme.

R5. Operating Reserve

- R5.1.** An Obligated Entities' Spinning Reserve shall be calculated at any given instant as the difference between the sum of the net Declared Capability of all generating units on line in the respective entity and the integrated Systems Demand of the system involved and other sources (for example, SILOS and BESS) or declared restrictions on spinning reserve (for example, Bradley Lake or tie line restrictions) as accepted by the IMC. See the Reserve Policy for spin performance criteria.
- R5.2.** An Obligated Entities' Spinning Reserve may be satisfied by an automatically controlled load shedding program (SILOS – Shed In Lieu of Spin). The load shedding program shall assure that controlled load can be dropped to meet the requirement of Spinning Reserve in such a manner as to maintain system stability and not cause degradation or cascading effects in the Railbelt system. The load included in the Under Frequency Load Shed system (UFLS) for the

protection of the interconnected system shall not be included in a SILOS program. Load included in an island's UFLS system designed to protect the area following islanding may be included in a SILOS program.

- R5.3.** The IMC may establish procedures to assure that the Operating Reserve of an entity is available on the Railbelt System at all times.
- R5.4.** Prudent Utility Practices shall be followed in distributing Operating Reserve, taking into account effective utilization of capacity in an Emergency, time required to be effective, transmission limitations and local area requirements. Available Transfer Capability (ATC) shall include a component (Capacity Benefit Margin) recognizing the need to move reserves between areas. Geographical constraints and remedies are defined in the Reserve Policy.
- R5.5.** Subject to R5.4 above, an entity may arrange for one or more other entities to supply part of, or its entire, Operating Reserve requirement.
- R5.6.** In an Emergency, any Generator Owner, upon request by its Balancing Authority shall supply such Balance Authority part or all of its Non Spinning Reserve up to the full amount of its available total Operating Reserve Obligation as indicated in R3.
- R5.7.** In an Emergency, any Generator Owner shall automatically supply to such Balancing Authority part or all of its Spinning Reserve obligation. An Obligated Entity experiencing an Emergency is not required to maintain its Operating Reserve Obligation. There shall be no obligation of an Obligated Entity to supply Operating Reserve if the requesting entity is not making full use of its own available Accredited Capacity.

R6. Responsibility for Regulating Reserve

- R6.1.** *Regulating Reserve*- each Balancing Authority shall provide, or contract for, Regulating Reserve equal to or greater than the Regulating Reserve Obligation of the party. Regulating Reserve may not overlap reserves dedicated for Spinning Reserve. Regulating Reserve (both up and down) is required to compensate for uncertainty in forecasting and is established during the unit commitment planning process, and as such the Balancing Authority may then utilize their reserve as required during the course of the day. If a Balancing Authority exhausts its Regulating Reserve, it is required to procure or commit additional reserves immediately. Available Transfer Capability (ATC) for interconnecting Transmission lines shall recognize a component included in Transmission Reliability Margin (TRM) to allow for the delivery of Regulating Reserve between areas.
- R6.2.** On an annual basis, after the year end CPS statistics are compiled, the RRO shall modify each Balancing Authorities' Regulating Reserve by increasing/decreasing its current Regulating Reserve by multiplying by 5 the % deviation in its CPS1. The Regulating Reserve obligations so calculated will be rounded up to the nearest integer MW. For example, if an Obligated Entity's CPS1 reaches 5% deviation (level 1 violation), the Obligated Entity will be required to increase its Regulating Reserve obligation by 25%.

- R6.3.** The IMC reserves the right to increase/decrease a Balancing Authorities' Regulating Reserve or require other measures at any time due to changes in the system or repeat infractions.

R7. Spinning Reserve Components

- R7.1.** The components determining the makeup of the spin obligation as well as the allocation is defined in the Reserve Policy.
- R7.2.** The Spinning Reserve Obligation (SRO) shall be converted to energy and may be called upon for up to an hour when the system is experiencing a generating deficiency.

C. Measures

- M1.** Each Obligated Entity and Balancing Authority shall maintain:

- M1.1.** Records of their available Accredited Capacity at any point in time. These records will be updated as new Generating Assets are added and other Generating Assets are retired. These records will be available by for review by the Balancing Authority or Compliance Monitor with 1 business week written notice.
- M1.2.** Hourly records of Operating Reserve and Regulating Reserve (scheduled and actual) will be maintained by all Obligated Entities'. These will be made available in real-time to the Balancing Authority for archival and storage.
- M1.3.** The Compliance Monitor will review the performance of each Balancing Authority and Obligated Entity at least annually. More frequent reviews shall be performed if spin obligation compliance warrants such reviews.

M1.4.

D. Compliance Monitoring

E. IMC or, if formed by the Utilities, a Regional Reliability Organization. Non-Compliance

Level 1.

Version History

Version	Date	Action	Change Tracking
0	June 7, 2013	Original	New
1	May 2, 2016	Per the IMC/RRO re-alignment	Change
2	October 20, 2016	Put allocation in Reserve Policy	Move
3	April 24, 2017	IOC Edits to Standard	On

Alaska Railbelt Standard AKTPL-001-4 Transmission Planning Performance Requirements

Definitions of Terms Used in Standard

This section includes all newly defined or revised terms used in the proposed standard. Terms already defined in the Intertie Management Committee Glossary of Terms, Version 1 – October 1, 2013 are not repeated here. New or revised definitions listed below become approved when the proposed standard is approved. When the standard becomes effective, these defined terms will be removed from the individual standard and added to the Glossary.

Resource Planner: Group that plans for and determines future resource needs for the BES, including generation and transmission improvements.

Source: AK proposed definition

Corrective Action Plan: The Corrective Action Plan (CAP) shall include Operational measures, such as reduced or revised transfer limits, system operating constraints, loss of firm load or suspension of firm transmission service, as well as long-term capital improvement plans.

The CAP shall include recommendations on longer term projects that are capable of eliminating the deficiencies identified in the system studies. Included in the plan for each of the projects must be:

- 1) Complete description of the proposed project
- 2) Complete cost estimate of the proposed project
- 3) Complete time frame of the project from project approval to project completion, including major milestones
- 4) Complete Cost/Benefit analysis using the costs above and the reduced operating costs and reliability improvements achieved over the life of the project
- 5) Be accepted by the IMC

Source: AK proposed definition

Regional Coordinating Council: The responsible entity that enforces, coordinates, and integrates reliability standards used by the Regional Reliability Organizations.

Source: AK proposed definition

A. Introduction

1. Title: Transmission System Planning Performance Requirements

2. Number: AKTPL-001-4

3. Purpose:

Establish Transmission system planning performance requirements within the planning horizon to develop a System that will operate reliably over a broad spectrum of conditions and following a wide range of probable Contingencies applicable to the portions of the Bulk Electrical System (BES) used to supply power to or from major load and generation centers.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

4.3. Resource Planner

5. Effective Date: TBD (Standard should be implemented as a test and monitored for a minimum of 12 months to ascertain ability to comply and monitor)

B. Requirements

R1. System Model

The IMC, in conjunction with each areas Transmission Planner, shall maintain System models for performing the studies needed to complete its Planning Assessment. The models shall use data consistent with that provided in accordance with the AKMOD-032-1 standard, supplemented by other sources as needed, including items represented in the CAP, and must represent projected System conditions. This establishes Category P0 as the normal System condition in Table 1.

R1.1. System models shall represent:

- R1.1.1.** Existing Facilities
- R1.1.2.** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.
- R1.1.3.** New planned Facilities and changes to existing Facilities
- R1.1.4.** Real and reactive Load forecasts
- R1.1.5.** Known commitments for Firm Transmission Service and Interchange
- R1.1.6.** Resources (supply or demand side) required for Load
- R1.1.7.** Resources required for Transmission stability or contingencies
- R1.1.8.** Future Facilities identified in BAL-502 Resource Adequacy analysis

R2. Assessment

The IMC, in conjunction with and each Transmission Planner and Planning Coordinator shall prepare a Planning Assessment of its portion of the BES no longer than every five years or as determined by the IMC. This Planning Assessment shall use current or qualified past studies (as indicated in R2.6), document assumptions, and document summarized results of the steady state analyses, short circuit analyses, and Stability analyses.

R2.1. Near Term – Steady State

For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed no longer than every five years or as determined by the IMC, and be supported by current studies or qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

- R2.1.1.** System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for Year One.
- R2.1.2.** System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year five.
- R2.1.3.** System Minimum Load (with minimum and maximum Intermittent Generation) for one of the five years.

- R2.1.4.** P1 events in Table 1, with known outages modeled as in Requirement 0, under those System Summer Peak, Winter Peak, or System Minimum conditions when known outages are scheduled.
- R2.1.5.** For each of the studies described in R2.1.1 through R2.1.5, sensitivity case(s) may be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment shall vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response: (as accepted by the IMC)
 - R2.1.5.1.** Real and reactive forecasted Load.
 - R2.1.5.2.** Expected transfers
 - R2.1.5.3.** Expected in-service dates of new or modified Transmission Facilities.
 - R2.1.5.4.** Reactive resource capability.
 - R2.1.5.5.** Generation additions, retirements.
 - R2.1.5.6.** Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.
 - R2.1.5.7.** Controllable Loads and Demand Side Management.
 - R2.1.5.8.** Duration or timing of known Transmission outages.
- R2.1.6.** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be studied. The studies shall be performed for the P0, P1, and P2, categories identified in Table 1 with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.
- R2.1.7.** Determine the actual Transfer Limits in accordance with AKMOD-029-1a for each line between Balance Authorities during each load level.

R2.2. Long Term – Steady State

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed no longer than every five years or as determined by the IMC, and be supported by the following current study, supplemented with qualified past studies as indicated in R2.6. Qualifying studies need to include the following conditions:

- R2.2.1.** For one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

- R2.2.2.** System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year selected.
- R2.2.3.** System Minimum Load (with minimum and maximum Intermittent Generation) for year selected.
- R2.2.4.** Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.3. Near Term – Short Circuit

The short circuit analysis portion of the Planning Assessment shall be conducted no longer than every five years or as determined by the IMC, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in R2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

R2.4. Near Term – Stability

For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed no longer than every five years or as determined by the IMC, and be supported by current or past studies as qualified in R2.6. The following studies are required:**R.2.4.1.** Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

- R2.4.2.** System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for one of the five years.
- R2.4.3.** System Minimum Load (with minimum and maximum Intermittent Generation) for one of the five years.
- R2.4.4.** For each of the studies described in R2.4.1 through R2.4.6, sensitivity case(s) may be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment shall vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance: (as accepted by the IMC)
 - R2.4.4.1.** Load level, Load forecast, or dynamic Load model assumptions.
 - R2.4.4.2.** Expected transfers.
 - R2.4.4.3.** Expected in service dates of new or modified Transmission Facilities.

R2.4.4.4. Reactive resource capability.

R2.4.4.5. Generation additions, retirements.

R2.4.4.6. Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.4.5. Determine the actual Transfer Limits in accordance with AKMOD-028 for each line between Balance Authorities during each load level.

R2.5. Long Term – Stability

For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed no longer than every five years or as determined by the IMC, to address the impact of proposed material generation additions or changes in that time frame and be supported by current or past studies as qualified in R2.6 and shall include documentation to support the technical rationale for determining material changes. Qualifying studies need to include the following conditions:

R2.5.1. For one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

R2.5.2. System Summer and Winter Peak Load (with minimum and maximum Intermittent Generation) for year selected.

R2.5.3. System Minimum Load (with minimum and maximum Intermittent Generation) for year selected.

R2.5.4. Unit commitment and Dispatch scenarios to maximize transfers between each load and generation area.

R2.6. Past Studies

Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

R2.6.2. For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. Documentation to support the technical rationale for determining material changes shall be included.

R2.7. Planning Analysis – CAP(s)

For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include CAP(s) detailing the plans to meet the performance requirements. The CAP(s) must:

R2.7.1. Include both operational measures, such as reduced or revised transfer limits, system operating constraints, loss of firm load or

suspension of firm transmission service, as well as long-term capital improvement plans.

- R2.7.2.** Include in the presentation of operational measures and/or capital projects that are capable of eliminating the deficiencies identified in the system studies:
1. Complete description of the proposed project
 2. Complete cost estimate of the proposed project
 3. Complete time frame of the project from project approval to project completion, including major milestones
 4. Complete Cost/Benefit analysis using the costs above and the reduced operating costs and reliability improvements achieved over the life of the project
- R2.7.3.** Be reviewed in subsequent annual Planning Assessments for continued validity and status of items in the CAP(s).
- R2.7.4.** If resource additions or changes are part of a CAP, the resources required in the CAP must be included as a proposed resource in AKBAL-502 for the corresponding time period.
- R2.7.5.** Provide the System operator any written summary of the recommended operating guidelines to mitigate the cause and/or effect of any deficiencies.

R2.8. Short Circuit – CAP

For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a CAP to address the Equipment Rating violations. The CAP must:

- R2.8.1.** List System deficiencies and the associated CAP needed to meet required System performance.
- R2.8.2.** Be reviewed in subsequent annual Planning Assessments for continued validity and status of items in the CAP.
- R2.8.3.** Steady State – Performance

For the steady state portion of the Planning Assessment, the IMC, the Planning Authority, and Transmission Planner shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in R2.1, and R2.2. The studies shall be based on computer simulation models using data provided in R1.

- R2.9.** Studies shall be performed for planning events to determine whether the System meets the performance requirements in Table 1 based on the Contingency list created in R3.4.
- R2.10.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in R3.5.

R2.11. Contingency analyses for R3.1 & R3.2 must:

R2.11.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R2.11.2. Simulate the expected automatic operation of existing and planned devices designed to provide steady state control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R2.12. Those planning events in Table 1, that are expected to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in R3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R2.12.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R2.13. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in R3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R2.13.1. Stability - Performance
For the Stability portion of the Planning Assessment, as described in Requirement R2, Parts 2.4 and 2.5, the IMC, Planning Authority, and Transmission Planner shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

R2.14. Studies shall be performed for planning events to determine whether the System meets the performance requirements in Table 1 based on the Contingency list created in R4.4.

R2.14.1. For planning event P1: No generating unit shall pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.

R2.14.2. For planning events P2 through P7: When a generator pulls out of synchronism in the simulations, the resulting apparent impedance swings shall not result in the tripping of any Transmission system

elements other than the generating unit and its directly connected Facilities.

- R2.14.3.** For planning events P1 through P7: Power oscillations shall exhibit acceptable damping as established by the Balancing Authority.
- R2.15.** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in R4.5.
- R2.16.** Contingency analyses for R4.1 and R4.2 must:
 - R2.16.1.** Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent:
 - R2.16.1.1.** Successful high speed (less than one second) reclosing and unsuccessful high-speed reclosing into a Fault where high speed reclosing is utilized.
 - R2.16.2.** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators and power flow controllers.
- R2.17.** Those planning events in Table 1 that are expected to produce more severe System impacts, shall be identified, and a list created of those Contingencies to be evaluated in R4.1. The rationale for those Contingencies selected for evaluation shall be available as supporting information.
 - R2.17.1.** The Planning Coordinator and Transmission Planner shall coordinate with their own Resource Planner and adjacent Planning Coordinators and Transmission Planners and Resource Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
- R2.18.** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in R4.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there is Cascading caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.
 - R2.18.1.** The IMC, Planning Authority, and Transmission Planner shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.

- R2.18.2.** The IMC, Planning Authority, and Transmission Planner shall define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding.
- R2.18.3.** The IMC, in conjunction with the Planning Coordinators and Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.
- R2.18.4.** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to the IMC within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of such a request.
- R2.18.5.** If a recipient of the Planning Assessment results provides documented comments on the results, the respective party shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Table 1 – Steady State & Stability Performance Planning Events

Steady State & Stability:					
a. The System shall remain stable. Cascading and uncontrolled islanding shall not occur.					
b. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0.					
c. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.					
d. Simulate Normal Clearing unless otherwise specified.					
e. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.					
Steady State Only:					
f. Applicable Facility Ratings shall not be exceeded.					
g. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits as established by the Planning Authority and Transmission Planner.					
h. Planning event P0 is applicable to steady state only.					
i. The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.					
Stability Only:					
j. Transient voltage response shall be within acceptable limits established by the Planning Authority and Transmission Planner.					

Category	Initial Condition	Event	Fault(s) Type ¹	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P0 No Contingency	Normal System	None	NA	No	No
P1 Single Contingency	Normal System	Loss of one of the following: 1. Generator, no fault 2. Generator 3. Transmission Circuits 4. Transformer ² 5. Shunt Device-Ancillary Service Device ³ 6. Single Pole of a DC line	N/A 3Ø SLG	No	No
P2 Single Contingency	Normal System	1. Opening a line section w/o fault ⁴ 2. Bus Section fault 3. Internal Breaker Fault ⁵ (non-Bus-tie Breaker) 4. Internal Breaker Fault (Bus-tie Breaker) ⁵	N/A SLG	No	No

Category	Initial Condition	Event	Fault(s) Type ¹	Interruption of Firm Transmission Service Allowed	Non-Consequential Load Loss Allowed
P3a Multiple Contingency	Loss of generator unit followed by System adjustments ⁶ Unit Commitment Changes Allowed for All Events	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer ² 4. Shunt Device/ Ancillary Service Device ³ 5. Single pole of a DC line	3Ø SLG	No	No
P3b Multiple Contingency	Loss of generator unit followed by System adjustments ⁶	Loss of one of the following: 1. Generator 2. Transmission Circuits 3. Transformer ² 4. Shunt Device/ Ancillary Service Device ³ 5. Single pole of a DC line	3Ø SLG	No	Yes, 10% of System Load No
P4 Multiple Contingency (Fault plus stuck breaker ⁷)	Normal System	Loss of multiple elements caused by a stuck breaker ⁷ (non-Bus-tie Breaker) attempting to clear a Fault on one of the following: 1. Generator 2. Transmission Circuits 3. Transformer ² 4. Shunt Device ³ 5. Bus Section 6. Loss of multiple elements caused by a stuck breaker ⁷ (Bus-tie Breaker) attempting to clear a Fault on the associated bus	SLG	Yes	Yes, 25% for Isolated Area Load, 10% of System Load
P5 Multiple Contingency (Fault plus relay failure to operate)	Normal System	Delayed Fault Clearing due to the failure of a non-redundant relay ⁹ protecting the Faulted element to operate as designed, for one of the following: 1. Generator 2. Transmission Circuits 3. Transformer ² 4. Shunt Device ³ 5. Bus Section	SLG	Yes	Yes, 25% for Isolated Area Load, 10% of System Load
P6 Multiple Contingency (Two overlapping singles)	Loss of one of the followed by System adjustments ⁶ 1. Transmission Circuits 2. Transformer ² 3. Shunt Device ³ 4. Single Pole of a DC Line	Loss of one of the following: 1. Transmission Circuits 2. Transformer ² 3. Shunt Device ³ 4. Single pole of a DC line	3Ø SLG	Yes	Yes, 25% for Isolated Area Load, 10% of System Load
P7 Multiple Contingency (Common Structure)	Normal System	The loss of: 1. Any two adjacent (vertically or horizontally) circuits on common structure. ⁸ 2. Loss of a bipolar DC line	SLG	Yes	Yes, 25% for Isolated Area Load, 10% of System Load

Table 1 – Steady State & Stability Performance Extreme Events

Steady State & Stability		
For all extreme events evaluated:		
1.	Simulate the removal of all elements that Protection systems and automatic controls are expected to disconnect for each Contingency.	
2.	Simulate Normal Clearing unless otherwise specified.	
Steady State		Stability
1.	Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service prior to System adjustments.	1. Loss of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer force out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.
2.	Local area events affecting the Transmission System such as:	2. Local or wide area events affecting the Transmission System such as:
	a. Loss of a tower line with three or more circuits ⁹ .	a. 3Ø fault on generator with stuck breaker ⁸ or a relay failure ¹⁰ resulting in Delayed Fault Clearing.
	b. Loss of all Transmission lines on a common Right-of-Way ⁹ .	b. 3Ø fault on Transmission circuit with stuck breaker ⁸ or a relay failure ¹⁰ resulting in Delayed Fault Clearing.
	c. Loss of a switching station or substation (loss of one voltage level plus transformers).	c. 3Ø fault on transformer with stuck breaker ⁸ or a relay failure ¹⁰ resulting in Delayed Fault Clearing.
	d. Loss of all generating units at a generating station.	d. 3Ø fault on bus section with stuck breaker ⁸ or a relay failure ¹⁰ resulting in Delayed Fault Clearing.
	e. Loss of a large Load or major Load center.	e. 3Ø internal breaker fault.
3.	Wide area events affecting the Transmission System based on System topology such as:	f. Other events based upon operating experience, such as consideration of initiating events that experience suggests may result in wide area disturbances.
	a. Loss of two generating stations resulting from conditions such as:	
	i. Loss of a large fuel line into an area.	
	ii. Loss of the use of a large body of water as the cooling source for generation.	
	iii. Wildfires	
	iv. Severe weather, e.g., hurricanes	
	v. A successful cyber attack	
	vi. Large earthquake, tsunami or volcanic eruption	
	b. Other events based upon operating experience that may result in wide area disturbances.	

**Table 1 – Steady State & Stability Performance Footnotes
(Planning Event and Extreme Events)**

1.	Unless specified otherwise, simulate Normal Clearing of faults. Single line to ground (SLG) or three-phase (3Ø) are the fault types that shall be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.
2.	For non-generator step up transformer outage events, the reference voltage, as used in footnote 1, applies to the low-side winding (excluding tertiary windings). For generator and Generator Step Up transformer outage events, the reference voltage applies to the System connected voltage (high-side of the Generator Step Up transformer). Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers.
3.	Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.
4.	Opening one end of a line section without a fault on a normally networked Transmission circuit such that the line is possibly serving Load radial from a single source point.
5.	An internal breaker fault means a breaker failing internally, thus creating a System fault which shall be cleared by protection on both sides of the breaker.
6.	An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed both as a System adjustment (as identified in the column entitled 'Initial Condition') and a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. System adjustments assume the system has been brought back to 60 Hz and transfers are adjusted based on the constraints of the reduced system.
7.	A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing.
8.	Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for 1 mile or less.
9.	Applies to the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 & 59), directional (#32, & 67), and tripping (#86, & 94).

C. Measures

- M1.** The IMC, Transmission Planner, and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models within their respective area, using data consistent with AKMOD-032-1, including items represented in the CAP, representing projected System conditions, and that the models represent the required information in accordance with R1.
- M2.** The IMC, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of its annual Planning Assessment, that it has prepared an annual Planning Assessment of its portion of the System in accordance with Requirement R2.
- M3.** The IMC, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment, in accordance with Requirement R3.
- M4.** The IMC, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of the studies utilized in preparing the Planning Assessment in accordance with Requirement R4.
- M5.** The IMC, Transmission Planner, and Planning Coordinator shall provide dated evidence such as electronic or hard copies of the documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System in accordance with Requirement R5.
- M6.** The IMC, Transmission Planner, and Planning Coordinator shall provide dated evidence, such as electronic or hard copies of documentation specifying the criteria or methodology used in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding that was utilized in preparing the Planning Assessment in accordance with Requirement R6.
- M7.** Each Transmission Planner and Planning Coordinator shall provide evidence, such as email notices, postal receipts showing recipient and date that it has distributed its Planning Assessment results to the IMC within 30 calendar days upon a written request for the information in accordance with Requirement R7.
- M8.** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to the IMC within 90 days of having completed its Planning Assessment, and to any functional entity who has indicated a reliability need within 30 days of a written request and that the IMC has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Enforcement Authority

IMC or, if formed by the Utilities, a Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Not Applicable

1.3. Compliance Monitoring and Enforcement Processes:

1.3.1 Compliance Audits

1.3.2 Self-Certifications

1.3.3 Spot Checking

1.3.4 Compliance Violation Investigations

1.3.5 Self-Reporting

1.3.6 Complaints

1.4. Data Retention

The IMC, Transmission Planner, and Planning Coordinator shall each retain data or evidence to show compliance as identified unless directed by the Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

1.4.1 The models utilized in the current in-force Planning Assessment and one previous Planning Assessment in accordance with Requirement R1 and Measure M1.

1.4.2 The Planning Assessments performed since the last compliance audit in accordance with Requirement R2 and Measure M2.

1.4.3 The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R3 and Measure M3.

1.4.4 The studies performed in support of its Planning Assessments since the last compliance audit in accordance with Requirement R4 and Measure M4.

1.4.5 The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.

1.4.6 The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

1.4.7 The current, in force documentation for the agreements(s) on roles and responsibilities, as well as documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7, and Measure M7.

The Planning Coordinator shall retain data or evidence to show compliance as identified unless directed by its Compliance Enforcement Authority to retain specific evidence for a longer period of time as part of an investigation:

- 1.4.8** Three calendar years of the notifications employed in accordance with Requirement R8 and Measure M8

If the Transmission Planner and Planning Coordinator is found non-compliant, it shall keep information related to the non-compliance until found compliant or the time periods specified above, whichever is longer.

2. Levels of Non-Compliance for Requirement R1, Measure M1

- 2.1. Level 1** - The IMC, Planning Authority's and Transmission Planner's System model failed to represent one of the Requirement R1, Parts 1.1.1 through 1.1.5 for Requirement R1 and Measurement M1.
- 2.2. Level 2** - The IMC, Transmission Planner and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R1 and Measurement M1.

3. Levels of Non-Compliance for Requirement R2, Measure M2

- 3.1. Level 1** - The IMC, Transmission Planner, and Planning Coordinator failed to comply with Requirement R2, Part 2.6 for Requirement R2 and Measurement M2.
- 3.2. Level 2** - The IMC, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R2 and Measurement M2.

4. Levels of Non-Compliance for Requirement R3, Measure M3

- 4.1. Level 1** - The IMC, Transmission Planner, and Planning Coordinator did not identify planning events as described in Requirement R3, Part 3.4 or extreme events as described in Requirement R3, Part 3.5 for Requirement R3 and Measurement M3.
- 4.2. Level 2** - The IMC, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R3 and Measurement M3.

5. Levels of Non-Compliance for Requirement R4, Measure M4

- 5.1. Level 1** - The IMC, Transmission Planner, and Planning Coordinator did not identify planning events as described in Requirement R4, Part 4.4 or extreme events as described in Requirement R4, Part 4.5 for Requirement R4 and Measurement M4.
- 5.2. Level 2** - The IMC, Transmission Planner, and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R4 and Measurement M4.

6. Levels of Non-Compliance for Requirement R5, Measure M5

- 6.1. Level 1** – N/A

- 6.2. **Level 2** - The IMC, Transmission Planner, and Planning Coordinator does not have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, or the transient voltage response for its System for Requirement R5 and Measurement M5.
- 7. **Levels of Non-Compliance for Requirement R6, Measure M6**
 - 7.1. **Level 1** – N/A
 - 7.2. **Level 2** - The Transmission Planner and Planning Coordinator failed to define and document the criteria or methodology for System instability used within its analysis as described in Requirement R6 for Requirement R6 and Measurement M6.
- 8. **Levels of Non-Compliance for Requirement R7, Measure M7**
 - 8.1. The Transmission Planner and Planning Coordinator distributed its Planning Assessment results to IMC / Regional Reliability Organization but it was more than 30 days but less than or equal to 40 days following the request as described in Requirement R7 for Requirement R7 and Measurement M7.
 - 8.2. The Transmission Planner and Planning Coordinator failed to meet all the requirements of Level 1 for Requirement R7 and Measurement M7.

Version History

Version	Date	Action	Change Tracking
0	-	Approved IMC	-
1	11/5/2015	EPS - Initial Edits	Yes
2	12/21/2015	EPS - Revision Edits	Yes
3	12/30/2015	EPS - Revision Edits	Yes
4	1/5/2016	EPS - Revision Edits	Yes
5	1/18/2016	EPS - Revision Edits	Yes
6	1/22/2016	EPS - Revision Edits	Yes
7	2/9/2016	EPS - Revision Edits	Yes
8	2/11/2016	Final Version	No
9	11/18/2016	EPS - Inclusion RRC	Yes
10	12/6/2016	Final	No
11	4/20/2016	IOC - Revision Edits	No

Alaska Railbelt Standard AKVAR-001-1— Voltage and Reactive Control

A. Introduction

1. Title: Voltage and Reactive Control

2. Number: AKVAR-001-1

3. Purpose:

To ensure that voltage levels, reactive flows, and reactive resources are monitored, controlled, and maintained within limits in real time to protect equipment and the reliable operation of the Interconnection.

4. Applicability:

4.1. Transmission Operators.

4.2. Purchasing-Selling Entities.

5. Effective Date: 1 month from package adoption.

B. Requirements

R1. Each Transmission Operator, individually and jointly with other Transmission Operators, shall ensure that formal policies and procedures are developed, maintained, and implemented for monitoring and controlling voltage levels and MVAR flows within their individual areas and with the areas of neighboring Transmission Operators.

R2. Each Transmission Operator shall acquire sufficient reactive resources within its area to protect the voltage levels under normal and Contingency conditions. This includes the Transmission Operator's share of the reactive requirements of interconnecting transmission circuits.

R3. The Transmission Operator shall specify criteria that exempt generators from compliance with the requirements defined in Requirement 4, and Requirement 6.1.

R3.1. Each Transmission Operator shall maintain a list of generators in its area that are exempt from following a voltage or Reactive Power schedule.

R3.2. For each generator that is on this exemption list, the Transmission Operator shall notify associated Generator Owner.

R4. Each Transmission Operator shall specify a voltage or Reactive Power schedule ¹ at the interconnection between the generator facility and the Transmission Owner's facilities to be maintained by each generator. The Transmission Operator shall provide the voltage or Reactive Power schedule to the associated Generator Operator and direct the Generator Operator to comply with the schedule in automatic voltage control mode (AVR in service and controlling voltage).

¹ The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period. The RRO will allow this up to the safe voltage/VAR limits of the equipment.

- R5.** Each Purchasing-Selling Entity shall arrange for (self-provide or purchase) reactive resources to satisfy its reactive requirements identified by its Transmission Service Provider.
- R6.** The Transmission Operator shall know the status of all transmission Reactive Power resources, including the status of voltage regulators and power system stabilizers.
 - R6.1.** When notified of the loss of an automatic voltage regulator control, the Transmission Operator shall direct the Generator Operator to maintain or change either its voltage schedule or its Reactive Power schedule.
- R7.** The Transmission Operator shall be able to operate or direct the operation of devices necessary to regulate transmission voltage and reactive flow.
- R8.** Each Transmission Operator shall operate or direct the operation of capacitive and inductive reactive resources within its area – including reactive generation scheduling; transmission line and reactive resource switching; and, if necessary, load shedding – to maintain system and Interconnection voltages within established limits. Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.
- R9.** Each Transmission Operator shall maintain reactive resources to support its voltage under first Contingency conditions.
 - R9.1.** Each Transmission Operator shall disperse and locate the reactive resources so that the resources can be applied effectively and quickly when Contingencies occur.
- R10.** Each Transmission Operator shall correct Interconnection Reliability Operating Limit (IROL) or System Operating Limit (SOL) violations resulting from reactive resource deficiencies (IROL violations must be corrected within 30 minutes) and complete the required IROL or SOL violation reporting.
- R11.** After consultation with the Generator Owner regarding necessary step-up transformer tap changes, the Transmission Operator shall provide documentation to the Generator Owner specifying the required tap changes, a timeframe for making the changes, and technical justification for these changes.
- R12.** The Transmission Operator shall direct corrective action, including load reduction, necessary to prevent voltage collapse when reactive resources are insufficient.

C. Measures

- M1.** The Transmission Operator shall have evidence it provided a voltage or Reactive Power schedule as specified in Requirement 4 to each Generator Operator it requires to follow such a schedule.
- M2.** The Transmission Operator shall have evidence to show that, for each generating unit in its area that is exempt from following a voltage or Reactive Power schedule, the associated Generator Owner was notified of this exemption in accordance with Requirement 3.2.

- M3.** The Transmission Operator shall have evidence to show that it issued directives as specified in Requirement 6.1 when notified by a Generator Operator of the loss of an automatic voltage regulator control.
- M4.** The Transmission Operator shall have evidence that it provided documentation to the Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with Requirement 11 of AKVAR-001-1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

IMC or, if formed by the Utilities, a Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Transmission Operator shall retain evidence for Measures 1 through 4 for 12 months.

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Transmission Operator shall demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance

- 2.1. Level 1:** No evidence that exempt Generator Owners were notified of their exemption as specified under R3.2.

- 2.2. Level 2:** There shall be a level two non-compliance if either of the following conditions exists:

- No evidence to show that directives were issued in accordance with R6.1.
- No evidence that documentation was provided to Generator Owner when a change was needed to a generating unit's step-up transformer tap in accordance with R11.

- 2.3. Level 3:** There shall be a level three non-compliance if either of the following conditions exists:

- Voltage or Reactive Power schedules were provided for some but not all generating units as required in R4.

- 2.4. Level 4:** No evidence voltage or Reactive Power schedules were provided to Generator Operators as required in R4.

E. Regional Difference

None identified.

Version History

Version	Date	Action	Change Tracking
0	June 7, 2013	Original	New
1	May 2, 2016	Voltage schedule range	Modify

Alaska Railbelt Standard AKVAR-002-1 — Generator Operation for Maintaining Network Voltage Schedules

A. Introduction

- 1. Title:** Generator Operation for Maintaining Network Voltage Schedules
- 2. Number:** AKVAR-002-1
- 3. Purpose:** To ensure generators provide reactive and voltage control necessary to ensure voltage levels, reactive flows, and reactive resources are maintained within applicable Facility Ratings to protect equipment and the reliable operation of the Interconnection.
- 4. Applicability**
 - 4.1.** Generator Operator.
 - 4.2.** Generator Owner.
- 5. Effective Date:** 1 month from package adoption

B. Requirements

- R1.** The Generator Operator shall operate each generator connected to the interconnected transmission system in the automatic voltage control mode (automatic voltage regulator in service and controlling voltage) unless the Generator Operator has notified the Transmission Operator.
- R2.** Unless exempted by the Transmission Operator, each Generator Operator shall maintain the generator voltage or Reactive Power output (within applicable Facility Ratings¹) as directed by the Transmission Operator.
 - R2.1.** When a generator's automatic voltage regulator is out of service, the Generator Operator shall use an alternative method to control the generator voltage and reactive output to meet the voltage or Reactive Power schedule directed by the Transmission Operator.
 - R2.2.** When directed to modify voltage, the Generator Operator shall comply or provide an explanation of why the schedule cannot be met.
- R3.** Each Generator Operator shall notify its associated Transmission Operator as soon as practical, but within 30 minutes of any of the following:
 - R3.1.** A status or capability change on any generator Reactive Power resource, including the status of each automatic voltage regulator and power system stabilizer and the expected duration of the change in status or capability.
 - R3.2.** A status or capability change on any other Reactive Power resources under the Generator Operator's control and the expected duration of the change in status or capability.

¹ When a Generator is operating in manual control, reactive power capability may change based on stability considerations and this will lead to a change in the associated Facility Ratings.

- R4.** The Generator Owner shall provide the following to its associated Transmission Operator and Transmission Planner within 30 calendar days of a request.
 - R4.1.** For generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage:
 - R4.1.1.** Tap settings.
 - R4.1.2.** Available fixed tap ranges.
 - R4.1.3.** Impedance data.
 - R4.1.4.** The +/- voltage range with step-change in % for load-tap changing transformers.
- R5.** After consultation with the Transmission Operator regarding necessary step-up transformer tap changes, the Generator Owner shall ensure that transformer tap positions are changed according to the specifications provided by the Transmission Operator, unless such action would violate safety, an equipment rating, a regulatory requirement, or a statutory requirement.
 - R5.1.** If the Generator Operator can't comply with the Transmission Operator's specifications, the Generator Operator shall notify the Transmission Operator and shall provide the technical justification.

C. Measures

- M1.** The Generator Operator shall have evidence to show that it notified its associated Transmission Operator any time it failed to operate a generator in the automatic voltage control mode as specified in Requirement 1.
- M2.** The Generator Operator shall have evidence to show that it controlled its generator voltage and reactive output to meet the voltage or Reactive Power schedule provided by its associated Transmission Operator as specified in Requirement 2.
- M3.** The Generator Operator shall have evidence to show that it responded to the Transmission Operator's directives as identified in Requirement 2.1 and Requirement 2.2.
- M4.** The Generator Operator shall have evidence it notified its associated Transmission Operator within 30 minutes of any of the changes identified in Requirement 3.
- M5.** The Generator Owner shall have evidence it provided its associated Transmission Operator and Transmission Planner with information on its step-up transformers and auxiliary transformers as required in Requirements 4.1.1 through 4.1.4
- M6.** The Generator Owner shall have evidence that its step-up transformer taps were modified per the Transmission Operator's documentation as identified in Requirement 5.
- M7.** The Generator Operator shall have evidence that it notified its associated Transmission Operator when it couldn't comply with the Transmission Operator's step-up transformer tap specifications as identified in Requirement 5.1.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

1.2. IMC or, if formed by the Utilities, a Regional Reliability Organization. Compliance Monitoring Period and Reset Time Frame

One calendar year.

1.3. Data Retention

The Generator Operator shall maintain evidence needed for Measure 1 through Measure 5 and Measure 7 for the current and previous calendar years.

The Generator Owner shall keep its latest version of documentation on its step-up and auxiliary transformers. (Measure 6)

The Compliance Monitor shall retain any audit data for three years.

1.4. Additional Compliance Information

The Generator Owner and Generator Operator shall each demonstrate compliance through self-certification or audit (periodic, as part of targeted monitoring or initiated by complaint or event), as determined by the Compliance Monitor.

2. Levels of Non-Compliance for Generator Operator

2.1. Level 1: There shall be a Level 1 non-compliance if any of the following conditions exist:

2.1.1 One incident of failing to notify the Transmission Operator as identified in R3.1, R3.2 or R5.1.

2.1.2 One incident of failing to maintain a voltage or reactive power schedule (R2).

2.2. Level 2: There shall be a Level 2 non-compliance if any of the following conditions exist:

2.2.1 More than one but less than five incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.2.2 More than one but less than five incidents of failing to maintain a voltage or reactive power schedule (R2).

2.3. Level 3: There shall be a Level 3 non-compliance if any of the following conditions exist:

2.3.1 More than five but less than ten incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.

2.3.2 More than five but less than ten incidents of failing to maintain a voltage or reactive power schedule (R2).

2.4. Level 4: There shall be a Level 4 non-compliance if any of the following conditions exist:

- 2.4.1 Failed to comply with the Transmission Operator’s directives as identified in R2.
- 2.4.2 Ten or more incidents of failing to notify the Transmission Operator as identified in R1, R3.1, R3.2 or R5.1.
- 2.4.3 Ten or more incidents of failing to maintain a voltage or reactive power schedule (R2).

3. Levels of Non-Compliance for Generator Owner:

- 3.1.1 **Level One:** Not applicable.
- 3.1.2 **Level Two:** Documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage was missing two of the data types identified in R4.1.1 through R4.1.4.
- 3.1.3 **Level Three:** No documentation of generator step-up transformers and auxiliary transformers with primary voltages equal to or greater than the generator terminal voltage.
- 3.1.4 **Level Four:** Did not ensure generating unit step-up transformer settings were changed in compliance with the specifications provided by the Transmission Operator as identified in R5.

E. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
1	January 15, 2016	Effective Date	New

Exhibit A

The following table lays out the functional assignments of Railbelt organizations. To the extent practical these assignments have been aligned with the NERC definitions, based on recent Railbelt history and the currently accepted operating plans of the Railbelt Utilities.

The terms and entity functional assignments found in the left column entitled “Entity Function” are found throughout the Railbelt Reliability Standards and are defined in the Railbelt Regional Reliability Standards Glossary.

Entity Function	AEA	AML	CEA	GVEA	MEA	IMC
Balancing Authority		X	X	X	X	
Compliance Enforcement Authority						X
Compliance Monitor						X
Distribution Provider		X	X	X	X	
Generator Operator		X	X	X	X	
Generator Owner	X	X	X	X	X	
Generation Planner		X	X	X	X	
Interchange Authority		X	X	X	X	
Load-Serving Entity		X	X	X	X	
Market Operator (Resource Integrator)						
Obligated Entity		X	X	X	X	
Reliability Coordinator		X				X
Planning Authority	X	X	X	X	X	X
Purchasing-Selling Entity		X	X	X	X	
Regional Reliability Organization						X
Reliability Assurer						X
Resource Planner		X	X	X	X	
Standards Developer						X
Transmission Operator		X	X	X	X	X
Transmission Owner	X	X	X	X	X	
Transmission Planner	X	X	X	X	X	X
Transmission Service Provider		X	X	X	X	X

Glossary of Terms Used in Railbelt Reliability Standards

Updated January 21, 2016

Introduction:

This Glossary lists each term that was defined for use in one or more of Railbelt Reliability Standards.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Accredited Capacity		5/2/16	The total amount of generator nameplate capacity and firm energy contracts under contract to a Load Serving Entity.
Adjacent Balancing Authority		11/18/10	A Balancing Authority Area that is interconnected with another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Annual System Demand		10/13/11	The highest System Demand occurring during the 12-month period ending with the current month.
Anti-Aliasing Filter		12/9/10	A filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE	5/2/16	The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, taking into account the effects of Frequency Bias and correction for meter error,
Area Interchange Error	AIE	5/2/16	The Balancing Authority's Interchange error(s) due to equipment failures or improper scheduling operations, or improper AGC performance.
Automatic Generation Control	AGC	12/9/10	Equipment that automatically adjusts generation in a Balancing Authority Area from a central location to maintain the Balancing Authority's interchange schedule plus Frequency Bias. AGC may also accommodate automatic inadvertent payback and time error correction.
Available Transfer Capability	ATC	5/2/16	A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less existing Transmission commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows.
Balancing Authority (Load Balancing Authority)	BA/LBA	5/2/16	The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time.
Balancing Authority Area (Load Balancing Area)		5/2/16	The collection of generation, transmission, and loads within the metered boundaries of the Balancing Authority. The Balancing Authority maintains load-resource balance within this area.
Blackstart Capability Plan		5/2/16	A documented procedure for a generating unit or station to

Railbelt-Wide Term	Acronym	Approved Date	Definition
			go from a shutdown condition to an operating condition delivering electric power without assistance from the electric system. This procedure is only a portion of an overall system restoration plan.
Bulk Electric System	BES	5/2/16	As defined by its Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 69 kV or higher.
Burden		12/9/10	Operation of the Bulk Electric System that violates or is expected to violate a System Operating Limit or Interconnection Reliability Operating Limit in the Interconnection, or that violates any other Railbelt, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices		5/2/16	Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices.
Capacity Benefit Margin	CBM	5/2/16	The amount of firm transmission transfer capability preserved by the transmission provider for Load-Serving Entities (LSEs), whose loads are located on that Transmission Service Provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.
Compliance Monitor		5/2/16	The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
Contingency		12/16/10	The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve		11/18/10	The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other Railbelt and Regional Reliability Organization contingency requirements.
Contingency Reserve Restoration Period		5/2/16	Begins at the end of the Disturbance Recovery Period and is 50 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by its Regional Reliability Organization.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Control Performance Standard	CPS	11/18/10	The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Curtailment		5/2/16	A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Declared Capability		5/2/16	Declared Capability- not less than the load (MW) on the unit at any point in time and not more than the temperature compensated maximum amount of load (MW) the unit is capable of supplying for a two-hour period or immediately supplying through the actions of AGC.
Demand		5/2/16	1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.
Distribution Provider	DP	5/2/16	Provides and operates the "wires" between the transmission system and the end-use customer. For those end-use customers who are served at transmission voltages, the Transmission Owner also serves as the Distribution Provider. Thus, the Distribution Provider is not defined by a specific voltage, but rather as performing the distribution function at any voltage.
Disturbance		11/18/10	1. An unplanned event that produces an abnormal system condition. 2. Any perturbation to the electric system. 3. The unexpected change in ACE that is caused by the sudden failure of generation or interruption of load.
Disturbance Control Standard	DCS	11/18/10	The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.
Disturbance Recovery Criterion		1/1/16	A Balancing Authority shall return its ACE to zero if its ACE just prior to the Reportable Disturbance was positive or equal to zero. For negative initial ACE values just prior to the Disturbance, the Balancing Authority shall return ACE to its pre-Disturbance value.
Disturbance Recovery Period		5/2/16	The default Disturbance Recovery Period is 10 minutes after the start of a Reportable Disturbance. This period may be adjusted to better suit the needs of an Interconnection based on analysis approved by the Reliability Assurer.
Dynamic Interchange Schedule or Dynamic Schedule		12/9/10	A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation

Railbelt-Wide Term	Acronym	Approved Date	Definition
			and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.
Emergency or BES Emergency		5/2/16	Any abnormal system condition that requires automatic or immediate manual action to prevent or limit the failure of transmission facilities or generation supply that could adversely affect the reliability of the Bulk Electric System.
Emergency Transfer Capability		TBD	The amount of electric power that can be moved or transferred from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under emergency conditions.
End User		10/6/11	Greater than 10 MW aggregate load that may be an independent entity or part of a utilities service area.
Facility Rating		5/2/16	The maximum or minimum voltage, current, frequency, or real or reactive power flow through a facility that does not violate the applicable equipment rating of any equipment comprising the facility.
Firm Demand		5/2/16	That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Generation or Firm Power		TBD	Power producing capacity intended to be available at all times during the period covered by a commitment even under adverse conditions.
Firm Transmission Service		5/2/16	The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Forecasted Peak Demand		TBD	The highest peak demand of the BA's forecasted system load requirements for the specified portion of the planning year.
Forced Outage		1/13/11	1. The removal from service availability of a generating unit, transmission line, or other facility for emergency reasons. 2. The condition in which the equipment is unavailable due to unanticipated failure.
Frequency Bias		11/18/10	A value, usually expressed in megawatts per 0.1 Hertz (MW/0.1 Hz), associated with a Balancing Authority Area that approximates the Balancing Authority Area's response to Interconnection frequency error.
Frequency Bias Setting		11/18/10	A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the

Railbelt-Wide Term	Acronym	Approved Date	Definition
			Balancing Authority to contribute its frequency response to the Interconnection.
Frequency Deviation		12/9/10	A change in Interconnection frequency.
Frequency Error		5/2/16	The difference between the actual and scheduled frequency. ($F_A - F_S$)
Frequency Regulation		12/9/10	The ability of a Balancing Authority to help the Interconnection maintain Scheduled Frequency. This assistance can include both turbine governor response and Automatic Generation Control.
Frequency Response		12/9/10	(Equipment) The ability of a system or elements of the system to react or respond to a change in system frequency. (System) The sum of the change in demand, plus the change in generation, divided by the change in frequency, expressed in megawatts per 0.1 Hertz (MW/0.1 Hz).
Generating Assets	GA	5/2/16	Primarily refers to machines synchronously connected to the Railbelt Grid providing real and reactive power. In some specialized instances these may include assets that are asynchronously connected to the Railbelt. Or, devices that provide only reactive power (synchronous condensers, SVC's, cables, wind turbines, FACTS etc.).
Generator Operator	GOP	5/2/16	The entity that operates generating unit(s) and performs the functions of supplying energy and Interconnected Operations Services.
Generator Owner	GO	5/2/16	Entity that owns and maintains generating units.
Host Balancing Authority		12/9/10	1. A Balancing Authority that confirms and implements Interchange Transactions for a Purchasing Selling Entity that operates generation or serves customers directly within the Balancing Authority's metered boundaries. 2. The Balancing Authority within whose metered boundaries a jointly owned unit is physically located.
Inadvertent Interchange		5/2/16	The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
Interchange		5/2/16	Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	IA	5/2/16	The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment

Railbelt-Wide Term	Acronym	Approved Date	Definition
			purposes.
Interchange Schedule		11/18/10	An agreed-upon Interchange Transaction size (megawatts), start and end time, beginning and ending ramp times and rate, and type required for delivery and receipt of power and energy between the Source and Sink Balancing Authorities involved in the transaction.
Interchange Transaction		11/18/10	An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interconnected Operations Service		5/2/16	A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric System.
Interconnected Value		5/2/16	The technical value of a generating asset to the Railbelt Grid and its subdivisions (LSE's, BAL's etc.) in terms of dispatch-ability, real and reactive power output and absorption, inertia, system response, operating and non-operating reserves, etc.
Interconnection		11/18/10	When capitalized, the Alaska Railbelt Interconnection.
Interconnection Reliability Operating Limit	IROL	5/2/16	The value (such as MW, MVar, Amperes, frequency or Volts) derived from, or a subset of the System Operating Limits, which if exceeded, could expose a widespread area of the Bulk Electric System to instability, uncontrolled separation(s) or cascading outages.
Intermediate Balancing Authority		5/2/16	A Balancing Authority Area that has connecting facilities in the Scheduling Path between the Sending Balancing Authority Area and Receiving Balancing Authority Area and operating agreements that establish the conditions for the use of such facilities.
Interruptible Demand		TBD	Demand not under direct control of the system operator that the end-use customer makes available to its BA via contract or agreement for curtailment. Interruptible Demand may include interruptible load that is not available for use in reducing the BA's forecast demand requirements due to contractual or implementation restrictions.
Largest Single Generation Contingency	LSGC	5/2/16	The declared Capability of the largest generating unit contingency (or combination of units with a single point of interconnection forming a single contingency regardless of RAS applications) interconnected to the Railbelt Grid.
Load Serving Entity	LSE	5/2/16	An entity that secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its

Railbelt-Wide Term	Acronym	Approved Date	Definition
			end-use customers.
Monthly Peak Hour Load	MPHL	5/2/16	The MPHL of an entity shall be defined as the monthly peak hour load from the month 1 year earlier. Adjustments for permanent loss, or expected increases due to large industrial loads may be made if agreed to by the Reliability Assurer. Economy sales are not counted as loads, but non-firm/interruptible loads are.
Net Actual Interchange		5/2/16	The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Interchange Schedule		5/2/16	The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Internal Demand		TBD	Total of all end-use customer demand and electric system losses within specified metered boundaries and period, and less Direct Control Load Management and Interruptible Demand.
Net Scheduled Interchange		5/2/16	The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Non-Spinning Reserve		12/9/10	1. That generating reserve not connected to the system but capable of serving demand within a specified time. 2. Interruptible load that can be removed from the system in a specified time.
Normal Net Capability		TBD	The maximum continuous rating of the resource minus the station service demand required to achieve the maximum continuous rating of the unit within the specified period. Station service or plant loads not attributable to the operation of the unit must not be included in the Normal Net Capability of the unit.
Obligated Entity		5/2/16	A Railbelt entity who is obligated to provide operating and or non-operating reserves or reserve capacity.
Off-Peak		12/9/10	Those hours between HE 2300 and HE 0600, weekdays and Saturdays and all hours Sunday. Also all hours on the following holidays; New Year's Day, Memorial Day, July 4th, Labor day, Thanksgiving and Christmas.
On-Peak		12/9/10	Those hours or other periods that are not Off-Peak
Operating Reserve		11/18/10	That capability above firm system demand required to provide for regulation, load forecasting error, equipment forced and scheduled outages and local area protection. It consists of spinning and non-spinning reserve.
Operating Reserve - Spinning		11/18/10	The portion of Operating Reserve consisting of: • Generation synchronized to the system and fully available to serve load within the Disturbance Recovery Period following the contingency event within operational or procedural limitations; or

Railbelt-Wide Term	Acronym	Approved Date	Definition
			• Load fully removable from the system within the Disturbance Recovery Period following the contingency event, for example SILOS. • Other approved sources.
Operating Reserve - Supplemental		11/18/10	The portion of Operating Reserve consisting of: • Generation (synchronized or capable of being synchronized to the system) that is fully available to serve load within the Disturbance Recovery Period following the contingency event; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event. • Other approved sources.
Overlap Regulation Service		5/2/16	A method of providing regulation service in which the Balancing Authority providing the regulation service incorporates another Balancing Authority's actual interchange, frequency response, and schedules into providing Balancing Authority's AGC/ACE equation.
Planning Authority	PA	5/2/16	The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Reserve Margin		TBD	The ratio of the total amount of planned available Firm Generation capacity divided by the Forecasted Peak Demand of the system minus 1.0, expressed in % for the specified period. The Planning Reserve Margin requirement must be calculated by each BA by system analysis.
Point of Delivery	POD	5/2/16	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction leaves or a Load-Serving Entity receives its energy.
Point of Receipt	POR	5/2/16	A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a generator delivers its output.
Postback		5/2/16	Positive adjustments to ATC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.
Power Electronics Transmission Asset		TBD	A device connected to the Bulk Electric system whose Real and Reactive Power outputs are controlled through the use of power electronics. Power Electronics Transmission Assets are not generation, but may produce Real and Reactive Power up to an energy limit. Power Electronics Transmission Assets include SVCs, STATCOMs, and Energy Storage

Railbelt-Wide Term	Acronym	Approved Date	Definition
			Devices.
Prudent Utility Practice		5/2/16	Shall mean at a particular time any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, would have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition, including but not limited to the regional practices, methods and acts engaged in or approved by a significant portion of the electrical utility industry prior thereto. In applying the standard of Prudent Utility Practices to any matter under these standards, equitable consideration should be given to the circumstances, requirements and obligations of each of the entities, and the fact that many of the entities are cooperatives, public corporations, or political subdivisions of the State of Alaska with prescribed statutory powers, duties and responsibilities. It is recognized that Prudent Utility Practice are not intended to be limited to the optimum practices, methods or acts to the exclusion of all others, but rather is a spectrum of possible practices, methods or acts which could have been expected to accomplish the desired result at the lowest reasonable cost consistent with reliability, safety and expedition. Prudent Utility Practices include due regard for manufacturers' warranties and the requirements of governmental authorities having jurisdiction.
Pseudo-Tie		12/9/10	A telemetered reading or value that is updated in real time and used as a "virtual" tie line flow in the AGC/ACE equation but for which no physical tie or energy metering actually exists. The integrated value is used as a metered MWh value for interchange accounting purposes.
Purchasing-Selling Entity	PSE	5/2/16	The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.
Railbelt (Railbelt Grid, Railbelt Interconnection, Railbelt System)		5/2/16	The <i>interconnected</i> generation and transmission system of Central Alaska, currently The Railbelt region extending from North of the Fairbanks area to the Kachemak bay area in the South. If used when describing an obligation, only those entities in the Railbelt that have IMC contractual responsibilities.
Reactive Power	VARs	5/2/16	The portion of electricity that establishes and sustains the electric and magnetic fields of alternating-current equipment. Reactive Power must be supplied to most types of magnetic equipment, such as motors and transformers. It also must supply the reactive losses on transmission facilities. Reactive Power is provided by generators, synchronous condensers, or electrostatic

Railbelt-Wide Term	Acronym	Approved Date	Definition
			equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kVAr) or megavars (MVar).
Receiving Balancing Authority		12/16/10	The Balancing Authority importing the Interchange.
Regional Coordinating Council		TBD	The responsible entity that enforces, coordinates, and integrates reliability standards used by the Regional Reliability Organizations.
Regional Reliability Organization	RRO	11/18/10	An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure.
Regulating Reserve		12/9/10	An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin.
Regulating Reserve Obligation		5/2/16	The minimum amount of regulating reserve required during day ahead planning.
Regulation Service		12/9/10	The process whereby one Balancing Authority contracts to provide corrective response to all or a portion of the ACE of another Balancing Authority. The Balancing Authority providing the response assumes the obligation of meeting all applicable control criteria as specified by its Regional Reliability Organization for itself and the Balancing Authority for which it is providing the Regulation Service.
Reliability Assurer		5/2/16	Monitors and evaluates the activities related to planning and operations, and coordinates activities of responsible entities to secure the reliability of the bulk power system.
Reliability Coordinator	RC	5/2/16	The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.
Reliability Coordinator Area		5/2/16	The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing

Railbelt-Wide Term	Acronym	Approved Date	Definition
			Authority Areas.
Remedial Action Scheme	RAS	5/2/16	See “Special Protection System”.
Reportable Disturbance		5/2/16	Contingencies involving any generating unit trips, transmission line trips, and distribution level disturbances that result in frequency deviation >.2 Hz. The definition of a reportable disturbance is specified by each Regional Reliability Organization. This definition may not be retroactively adjusted in response to observed performance.
Reserve Capacity Obligation		5/2/16	For any year, shall be equal to thirty (30) percent of the projected Annual System Demand for that year for that Load Serving Entity.
Reserve Margin		TBD	The ratio of the actual total amount of available Firm Generation capacity, expressed in %, between the total available Firm Generation capacity divided by the Peak Demand of the system minus 1.0, expressed in % for the specified period.
Reserve Sharing Group	RSG	11/18/10	A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating reserves required for each Balancing Authority’s use in recovering from contingencies within the group. Scheduling energy from an Adjacent Balancing Authority to aid recovery need not constitute reserve sharing provided the transaction is ramped in over a period the supplying party could reasonably be expected to load generation in (e.g., ten minutes). If the transaction is ramped in quicker (e.g., between zero and ten minutes) then, for the purposes of the Disturbance Control Standard, the areas become a Reserve Sharing Group.
Resource Adequacy		TBD	The ability of supply-side and demand-side resources to meet the aggregate electrical demand (including losses within a BA’s area) at all times within the specified period taking into account scheduled and reasonably expected unscheduled outages of system elements.
Resource Planner	RP	5/2/16	The entity that develops a long-term (generally one year and beyond) plan for the resource adequacy of specific loads (customer demand and energy requirements) within a Planning Authority area.
Schedule		12/9/10	(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
Scheduled Frequency		12/9/10	60.0 Hertz, except during a time correction.
Scheduling Entity		12/9/10	An entity responsible for approving and implementing Interchange Schedules.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Scheduling Path		5/2/16	The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
Sending Balancing Authority		12/16/10	The Balancing Authority exporting the Interchange.
Shed In Lieu Of Spin	SILOS	11/18/10	Computer or relay based load shedding scheme with timing and frequency parameters approved by its Regional Reliability Organization. This is not to be confused with system coordinated under-frequency load shedding.
Sink Balancing Authority		12/16/10	The Balancing Authority in which the load (sink) is located for an Interchange Transaction. (This will also be a Receiving Balancing Authority for the resulting Interchange Schedule.)
Source Balancing Authority		12/16/10	The Balancing Authority in which the generation (source) is located for an Interchange Transaction. (This will also be a Sending Balancing Authority for the resulting Interchange Schedule.)
Special Protection System (Remedial Action Scheme)	SPS	5/2/16	An automatic protection system designed to detect abnormal or predetermined system conditions, and take corrective actions other than and/or in addition to the isolation of faulted components to maintain system reliability. Such action may include changes in demand, generation (MW and Mvar), or system configuration to maintain system stability, acceptable voltage, or power flows. An SPS does not include (a) underfrequency or undervoltage load shedding or (b) fault conditions that must be isolated or (c) out-of-step relaying (not designed as an integral part of an SPS). Also called Remedial Action Scheme.
Spin Balancing Account	SBA	5/2/16	Procedures to track small changes in spin obligations due to forecasting errors.
Spinning Reserve		12/9/10	See Operating Reserve - Spinning
Spinning Reserve Obligation	SRO	5/2/16	The amount of spinning reserve an Obligated Entity is required to maintain.
Stability Limit		TBD	The maximum power flow possible through some particular point in the system while maintaining stability in the entire system or the part of the system to which the stability limit refers.
Steady-State Transfer Capability		TBD	The capability of a transmission system to reliably transfer electric power from one area to another by way of all transmission lines (or paths). The Steady-State Transfer Capability is equal to the Steady-State Transfer Limit minus Contingency Reserve obligations of source area and Transmission Reliability Margin.
Steady-State Transfer Limit		TBD	The amount of electric power that can be moved or

Railbelt-Wide Term	Acronym	Approved Date	Definition
			transferred from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) before a contingency event would result in unacceptable system response.
Supplemental Regulation Service		12/9/10	A method of providing regulation service in which the Balancing Authority providing the regulation service receives a signal representing all or a portion of the other Balancing Authority's ACE.
System		5/2/16	A combination of generation, transmission, and distribution components.
System Demand		10/13/11	That number of kilowatts which is equal to the kilowatt-hours required in any clock hour, attributable to energy required during such hour for supply of energy to an entities' consumers, including system losses, and wheeling losses occurring on other systems. System Demand excludes generating station uses.
System Operating Limit	SOL	5/2/16	The value (such as MW, MVAR, Amperes, frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to: • Facility Ratings (Applicable pre- and post- Contingency equipment or facility ratings) • Transient Stability Ratings (Applicable pre- and post- Contingency Stability Limits) • Voltage Stability Ratings (Applicable pre- and post- Contingency Voltage Stability) • System Voltage Limits (Applicable pre- and post- Contingency Voltage Limits).
System Operator		5/2/16	An individual at a control center (Balancing Authority, Transmission Operator, Generator Operator, Reliability Coordinator) whose responsibility it is to monitor and control that electric system in real time
System Reserve Basis	SRB	5/2/16	The amount of Spinning Reserve required to prevent first stage load-shed. Generally determined by system studies of the frequency response of the system under various conditions for the loss of the Largest Single Generation Contingency.
Temperature Sensitive Units		TBD	A generating unit whose maximum real power capability changes by more than 10 percent due to change in ambient air temperature. The 10 percent change in real power capability is based on the local average annual maximum and annual minimum ambient air temperatures.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Tie Line		12/9/10	A circuit connecting two Balancing Authority Areas.
Tie Line Bias		12/9/10	A mode of Automatic Generation Control that allows the Balancing Authority to 1.) maintain its Interchange Schedule and 2.) respond to Interconnection frequency error.
Tie Line Deviation		8/11/11	See Inadvertent Interchange.
Time Error		12/9/10	The difference between the Interconnection time measured at the Balancing Authority(ies) and the time specified by the National Institute of Standards and Technology. Time error is caused by the accumulation of Frequency Error over a given period.
Time Error Correction		12/9/10	An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.
Time Monitor		5/2/16	The entity that monitors Time Error and initiates or terminates corrective action orders in accordance with the Time Error Correction procedure.
Total Operating Reserve Obligation		5/2/16	At any time shall be an amount equal to 150 percent of the System Reserve Basis of the Railbelt Grid and may be composed of both spinning and non-spinning reserve.
Total Transfer Capability	TTC	5/2/16	The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.
Transient Transfer Limit		TBD	Stability Limit minus the Transmission Reliability Margin.
Transaction		12/9/10	See Interchange Transaction.
Transmission		12/9/10	An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems. Generally operated at or above 69 kV.
Transmission Constraint		12/9/10	A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
Transmission Customer		12/9/10	1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity.
Transmission Line		12/9/10	A system of structures, wires, insulators and associated hardware that carry electric energy from one point to another in an electric power system. Lines are operated at relatively high voltages varying from 69 kV up to 765 kV, and are capable of transmitting large quantities of electricity over long distances.

Railbelt-Wide Term	Acronym	Approved Date	Definition
Transmission Operator	TOP	12/9/10	The entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.
Transmission Operator Area		12/9/10	The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	TO	5/2/16	The entity that owns and maintains transmission facilities.
Transmission Planner	TP	5/2/16	The entity that develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within its portion of the Planning Authority area.
Transmission Reliability Margin	TRM	5/2/16	The amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.
Transmission Service		12/9/10	Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery.
Transmission Service Provider	TSP	5/2/16	The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.
Wide Area		5/2/16	The entire Reliability Coordinator Area as well as the critical flow and status information from adjacent Reliability Coordinator Areas as determined by detailed system studies to allow the calculation of Interconnection Reliability Operating Limits.

Exhibit-C Sanctions Matrix for Non Compliance

	Number of Occurrences at a Given Level within Specified Period			
Level of Non-Compliance	1	2	3	4 or more
Level 1	Letter (A)	Letter (A)	Letter (A)	Letter (B)
Level 2	Letter (A)	Letter (A)	Letter (B)	Letter (B)
Level 3	Letter (A)	Letter (A)	Letter (B)	Letter (B)
Level 4	Letter (A)	Letter (B)	Letter (B)	Letter (B)

Letter (A) is letter to management

Letter (B) is letter to Board

Specified Period is calendar year

Exhibit D-Railbelt Reliability Planning Guidelines:

During all excursions subsequent to the occurrence of Category B or probable Category C contingency, the following parameters should be maintained within applicable Emergency limits without system separation or instability:

Quantity Level:	Minimum	Maximum
First Power Swing:	0.80 pu V	1.10 pu V (< 0.5 sec.)
Intermediate:	0.92 pu V	1.05 pu V
Steady State:	0.95 pu V	1.05 pu V
Frequency:	58.8 Hz	61.5 Hz

Exhibit E- Railbelt Under Frequency Load shed Schedule

Subsequent to the 1989 blackout of the Railbelt Grid, the Intertie Operating Committee (IOC) (the predecessor to the Intertie Management Committee/Operating Sub-Committee) directed its Relay and Reliability Sub-committee (RRSC) evaluate the load shed scheme in place at that time.

The Pre-1993 scheme consisted of 13 shed points beginning at 59.3 Hz and ending with CEA/MEA Teeland separation at 57.7 Hz. The CEA/HEA separation at Quartz Creek had been disarmed by agreement with HEA in the late 1980's.

Using Power Technologies Inc. (PTI) and their power system simulator/electrical (PSS/E) program to run the bulk of the studies, with the RRSC performing QA/QC, the RRSC undertook extensive system studies in both powerflow and dynamic stability. These studies were performed in concert with the Bradley Lake integration studies which were being performed at the same time. The Bradley Lake studies were performed under the auspices of the Technical Coordinating Sub-committee (TCC) of the Bradley Lake Project Management Committee (BPMC). As today, the members of both of these committees were much the same. The major difference Fairbanks Municipal Utilities Systems (FMUS) was a member of the IOC and not a Bradley participant, while SES was a Bradley participant and not a member of the IOC.

The outcome of these studies is the load shed scheme delineated in Table -1 below, in the green  cells. Subsequent modifications to the study were made by the IOC and following the system blackouts of 1994 and 1995 these are indicated by the values in the cells in goldenrod . Outside the Chugach system other undocumented changes may have been made in the intervening years.

Table-1

Railbelt Underfrequency Loadshed Summary										
(As Adopted by the Intertie Operating Committee- 3/19/1993)*										
	Balancing Authority		CEA	AML	CEA	CEA	GVEA	GVEA		
	Load Serving Entity		Chugach	AML&F	HEA	MEA	GVEA	GVEA ROC+Hz**	% of MW Value	Comment
Load Shed Stage	Frequency Set Point (Hz)	Delay (Cycles)	(%)	(%)	(%)	(%)	(%)	(%)		
SILOS	59.8	120					25%		Spinning Reserve Obligation	
SILOS	59.7	120		25%					Spinning Reserve Obligation	IOC Approved- August 1994
SILOS	59.4	120		25%			25%		Spinning Reserve Obligation	IOC Approved- August 1994
Stage I Supplemental	59.3	9						13%	Total Load	
Stage I Supplemental	59.2	9						12%	Total Load	
SILOS	59.1	120		50%			50%		Spinning Reserve Obligation	IOC Approved- August 1994
Stage I Supplemental	59.1	9						10%	Total Load	
SILOS	59.1	1	100%						Spinning Reserve Obligation	IOC Approved- August 1994
Stage I	59.0	6	10%	10%	10%	10%	10%		Total Load	
Stage II Supplemental	58.9	6						10%	Total Load	
	58.8	6								
Stage II	58.7	6	10%	10%	10%	10%	10%		Total Load	
	58.6	6					12%		Total Load	
Stage III	58.5	6	10%	10%	15%	10%			Total Load	
Stage IV	58.5	30	7%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	35	10%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	40	9%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	45	7%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	50	7%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	55	6%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.5	60	8%						Total Load	Implemented after 1994 Blackout No IOC Approval
	58.4	6					Island		Separate GVEA and Southern System	
	58.3	6								
Stage IV Supplemental	58.2	6			40%				Total Load	
	58.1	6								
	58.0	6								
	57.9	6								
	57.8	6								
	57.7	9		Island					AML and Chugach	Implemented after 1995 Blackout No IOC Approval
	57.6	6								
	57.5	6								
	57.4	6								
	57.3	6								
* With Known Changes										
** Without BESS ROC Supervised for Intertie Trip										
SES contributes to loadshed by virtue of a crossing tripping tie that opens the SES 115 line on Loss of the Kenai-Anch 115 kV line for Kenai Imports greater than 15 MW.										