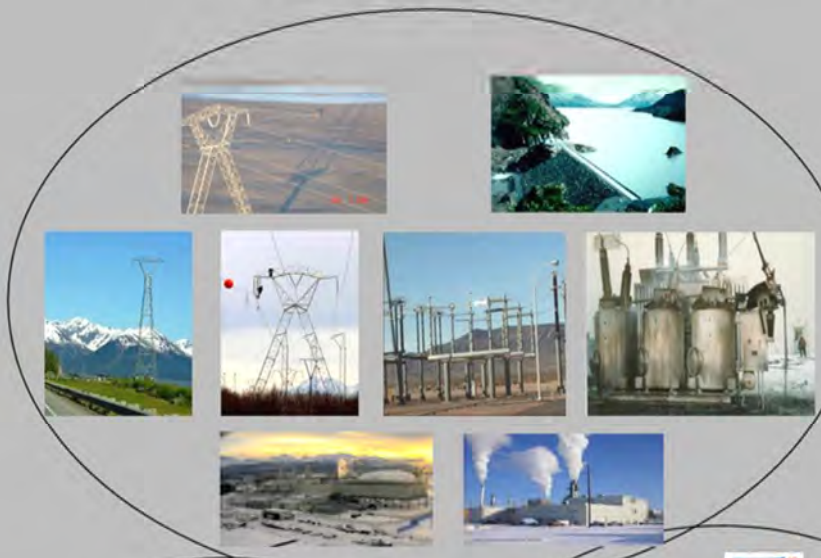
RAILBELT OPERATING AND RELIABILITY STANDARDS

ADOPTED BY THE INTERTIE MANAGEMENT COMMITTEE

UPDATED OCTOBER 2013

ADOPTED NOVEMBER 2013



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 Councils "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 Tripartite Agreement, the Bradley Lake Agreements, and The Alaska Intertie agreement as amended Nov. 2011 etc.

- The "Glossary of Terms Used in NERC Reliability Standards"

- The "IEEE Standard Dictionary of Electrical and Electronic terms"

- Webster's "2013 Dictionary of the English Language"

Further, to aid in understanding and implementing these requirements and criteria, the Intertie Management Committee (IMC) will require potential entities 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 AKRES standard is the reserves policy 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. These standards have some amount of behavior modification built into them in that they have formulas that will incentivize an entity's compliance with the standards in the event of nonperformance. It should be noted that these formulas are for minor infractions, and that for willful infractions further additional and more stringent sanctions may be warranted. Balancing Authorities with small units (less that 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 AKTPL's are the standards dealing with contingency categorization and reporting under normal and emergency conditions.

The Interconnection Standards for Generation and Transmission are documents developed strictly for the Railbelt. They are based on the principles that were used in the development of "Non-utility Generation Interconnection Standards" in place in the Railbelt utilities at the time of drafting (primarily GVEA and Chugach). These distributions system standards were modified to reflect Generation and Transmission and Generation Interconnection issues. These standards are applicable to entities/equipment, ***where a single contingency (Class 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 Glossary of terms used in Railbelt Reliability 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.

Each Entity desiring to interconnect to the Railbelt System must fill out an Entity Function Matrix 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.

THE INTERTIE MANAGEMENT COMMITTEES' RAILBELT OPERATING AND RELIABILITY STANDARDS

Table of Contents

Alaska Standard AKBAL-001-0 – Real Power Balancing Control Performance

Alaska Standard AKBAL-002-0 – Disturbance Control Performance

: Alaska Standard AKBAL-003-0 – Frequency Response and Bias

Alaska Standard AKBAL-004-0 – Time Error Correction

Alaska Standard AKBAL-005-0 – Automatic Generation Control

Alaska Standard AKBAL-006-0 – Inadvertent Interchange

Alaska Standard AKFAC-001-0 – Facility Connection Requirements

Alaska Standard AKFAC-002-0 – Coordination of Plans for New Facilities

Alaska Standard AKRES-001-0 – Reserve Obligation and Allocation

Alaska Standard AKTPL-001-0 – System Performance Under Normal Conditions

Alaska Standard AKTPL-002-0 – System Performance Following Loss of a Single BES Element and Likely Subsequent Contingencies

: Alaska Standard AKTPL-003-0 – System Performance Following Loss of Two or More BES Elements

Alaska Standard AKVAR-001-1 – Voltage and Reactive Control

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

Exhibit A: Entity Functional Assignments

Exhibit B: Railbelt Glossary of Terms Final Draft

Exhibit C: Sanctions Matrix

Exhibit D: Railbelt Reliability Planning Guidelines

Exhibit E: Railbelt Under Frequency Load Shed Scheme

Exhibit F: ASCC Operating Guides – Interconnected Utilities – February 1992

Exhibit G: ASCC Planning Criteria for Reliability of Interconnected Electric Utilities - May 1991

Interconnection Standards for Railbelt Generation

Interconnection Standards for Railbelt Transmission

Alaskan Railbelt Standard AKBAL-001-0 — Real Power Balancing Control Performance

A. Introduction

1. **Title**: **Real Power Balancing Control Performance**
2. **Number**: AKBAL-001-0
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:** TBD

B. Requirements

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 Railbelt Reliability Committee.

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

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:

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

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.

R3. 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.

R4. 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:

$$CF = \frac{CF_{12-\text{month}}}{(\in_1)^2}$$

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.

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

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

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).

$$\text{CF}_{\text{clock-hour average-month}} = \frac{\sum\limits_{\text{days-in-month}} [(\text{CF}_{\text{clock-hour}})(n_{\text{one-minute samples in clock-hour}})]}{\sum\limits_{\text{days-in month}} [n_{\text{one-minute samples in clock-hour}}]}$$

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

The 12-month compliance factor becomes:

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

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. **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:

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

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

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

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

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

Regional Reliability Organization.

1.2. 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.

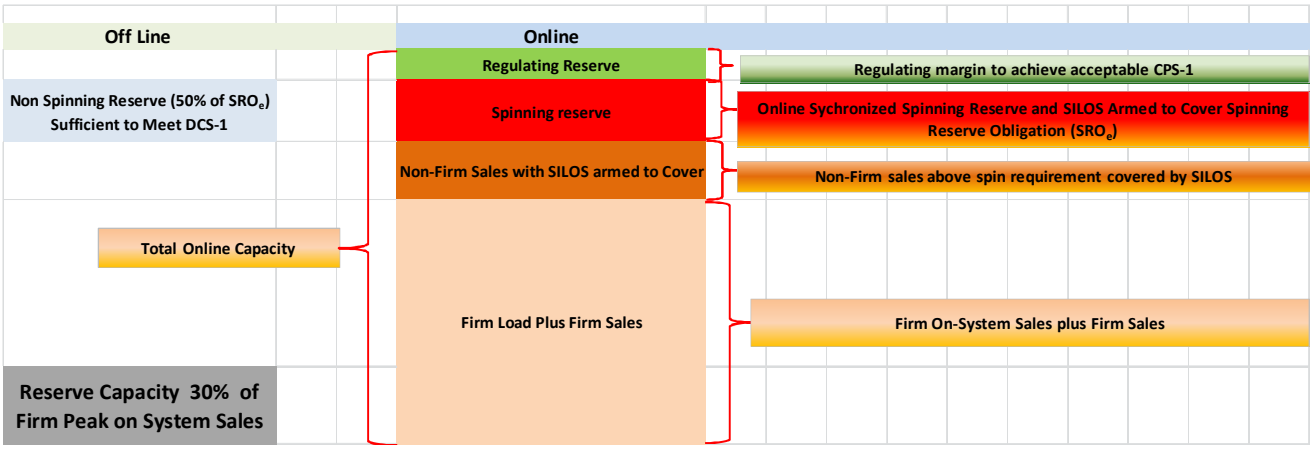
Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Attachment 1-AKBAL-001-0
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.


Off Line
Online
Regulating Reserve
Regulating margin to achieve acceptable CPS-1
Non Spinning Reserve (50% of SRO$_e$) Sufficient to Meet DCS-1
Spinning reserve
Online Sychronized Spinning Reserve and SILOS Armed to Cover Spinning Reserve Obligation (SRO$_e$)
Non-Firm Sales with SILOS armed to Cover
Non-Firm sales above spin requirement covered by SILOS
Total Online Capacity
Firm Load Plus Firm Sales
Firm On-System Sales plus Firm Sales
Reserve Capacity 30% of Firm Peak on System Sales

Alaska Standard AKBAL-002-0 — Disturbance Control Performance

A. Introduction

1. Title: Disturbance Control Performance

2. Number: **AK**BAL-002-0

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 Standard 002 through participation in a Reserve Sharing Group.)

4.3. Regional Reliability Organizations

5. Effective Date:

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, loadshed, 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 BAL-002.

R2. Each 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 UF loadshed/spinning reserve/droop coordination study

R2.2. Its allocation among members, as defined in the Reserve Policy, and as modified by coordinated Railbelt UF loadshed/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 15 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 Railbelt Reliability Committee.

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 90 minutes. This period may be adjusted to better suit the reliability targets of the Interconnection based on analysis approved by the Railbelt Reliability Committee.

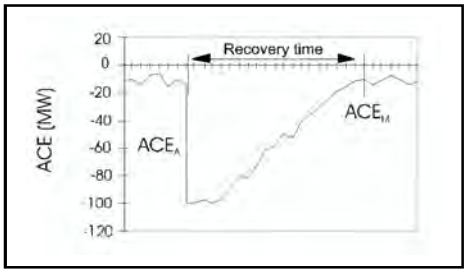
C. Measures

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:

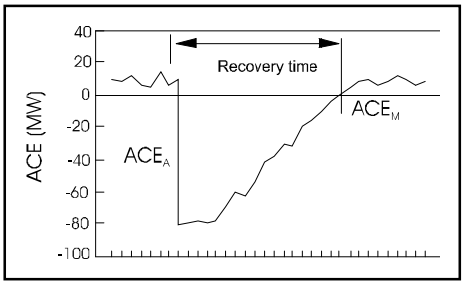
if $ACE_A < 0$
then

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



if $ACE_A \geq 0$
then

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

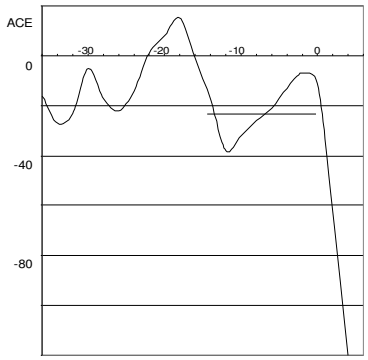


where:

- 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 fifteen minutes following the Disturbance. A Balancing Authority or Reserve Sharing Group may, at its discretion, set $ACE_M = ACE_{15\ min}$, 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 MW.



The average percent recovery is the arithmetic average of all the calculated R_i's for Reportable Disturbances during a given quarter. Average percent recovery is similarly calculated for excludable Disturbances.

D. Compliance

1. Compliance Monitoring Process

Compliance with the DCS shall be measured on a percentage basis as set forth in the measures above.

Each Balancing Authority or Reserve Sharing Group shall submit one completed copy of DCS Form, "Alaskan Railbelt Control Performance Standard Survey – All Interconnections" to its Resources Subcommittee Survey Contact no later than the 10th day following the end of the calendar quarter (i.e. April 10th, July 10th, October 10th, January 10th).

1.1. Compliance Monitoring Responsibility

IMC-Regional Reliability Organization.

1.2. Compliance Monitoring Period and Reset Timeframe

Compliance for DCS will be evaluated for each reporting period. Reset is one calendar quarter without a violation.

1.3. Data Retention

The data that support the calculation of DCS are to be retained in electronic form for at least a one-year period. If the DCS data for a Reserve Sharing Group and Balancing 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.

1.4. Additional Compliance Information

Reportable Disturbances – Reportable Disturbances are contingencies involving any generating unit trips, transmission line trips, and distribution level disturbances that result in frequency deviation >.2 Hz. A Regional Reliability Organization, sub-Regional Reliability Organization or Reserve Sharing Group may optionally reduce this criteria, provided that normal operating characteristics are not being considered or misrepresented as contingencies. Normal operating characteristics are excluded because DCS 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
001	11-1-2013	Approved -IMC	

Alaska Standard AKBAL-003-0 — Frequency Response and Bias

A. Introduction

1. **Title: Frequency Response and Bias**
2. **Number:** **AK**BAL-003-0
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:** TBD

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 Railbelt Reliability Committee.

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.

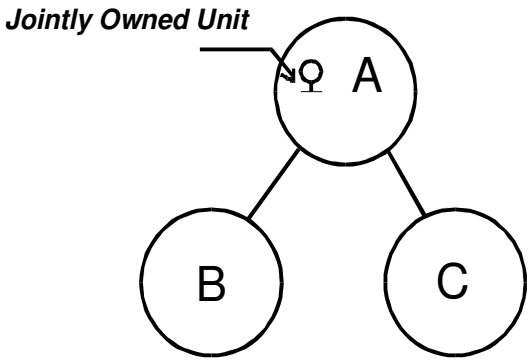
R2.2. The Balancing Authority may use a variable (linear or non-linear) bias value, which is based on a variable function of Tie Line deviation to Frequency Deviation. The Balancing Authority shall determine the variable frequency bias value by analyzing Frequency Response as it varies with factors such 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 Railbelt Reliability Committee to determine the Balancing Authority's response to Interconnection Frequency Deviations.

F. Compliance Monitor

IMC-Railbelt Regional Reliability Organization

C. Non-Compliance

Level 1.

D. Regional Differences

None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Alaska Standard AKBAL-004-0 — Time Error Correction

A. Introduction

1. **Title:** **Time Error Correction**
2. **Number:** **AK**BAL-004-0
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.
4. **Applicability:**
   - **4.1.** Reliability Coordinators
   - **4.2.** Balancing Authorities
5. **Effective Date:**

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 Railbelt Reliability Committee 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
001	11-1-2013	Approved -IMC	

Alaska Standard AKBAL-005-0 — Automatic Generation Control

A. Introduction

1. **Title:** **Automatic Generation Control**
2. **Number:** **AK**BAL-005-0
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 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:** TBD

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

Balancing Authorities shall be prepared to supply data to the Railbelt Reliability Committee in the format defined below:

1.1.1. Within one week upon request, Balancing Authorities shall provide the Railbelt Reliability Committee or 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 Railbelt Reliability Committee or the Regional Reliability Organization 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 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
001	11-1-2013	Approved -IMC	

Alaska Standard AKBAL-006-0 — Inadvertent Interchange

A. Introduction

1. **Title:** **Inadvertent Interchange**

2. **Number:** **AK**BAL-006-0

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** TBD

B. Requirements

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

R2. Each Balancing Authority shall include all AC 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 Actual Net 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 Regional

Reliability Organization Contact. The report shall describe the nature and the cause of the dispute as well as a process for correcting the discrepancy. By mutual agreement with respect to scheduling Bradley Lake losses, and if other arrangements have not been made:

- Losses shall be accumulated as an after the fact scheduled transaction.
- However losses will not be added to the hourly or accumulated inadvertent.
- Losses will be scheduled to be returned to the BA in which the losses occurred in the same hour they were accumulated 48 hours later as a Bradley Lake loss payback schedule.
- It is recognized that Sundays and holidays are off peak days but there will be no distinction at this time between those days and a standard on peak/off peak day. This may change at a future date.

The intent of this modification to current operating practice is to simplify accounting and provide for a more accurate accounting of inadvertent power flows.It is not the intent of this language to provide long-term gain to any participant in the payback of on-peak losses. In the event of documented abuse of this practice the standard will be revised by the Railbelt Reliability Committee.

R5. Reserved for future use.

C. Measures None Specified

D. Compliance Monitor

IMC-Railbelt Reliability Organization

E. Compliance

1. Compliance Monitoring Process

1.1. Each Balancing Authority shall maintain a monthly summary of Inadvertent Interchange available to the Railbelt Reliability Committee 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 Railbelt Reliability Committee 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 Railbelt Reliability Committee.

2. Levels of Non Compliance

A Balancing Authority that neither submits a report to the Regional Reliability Organization, 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
001	11-1-2013	Approved -IMC	

Alaska Standard AKFAC-001-0 — Facility Connection Requirements

A. Introduction

1. Title: Facility Connection Requirements

2. Number: **AK**FAC-001-0

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: TBD

B. Requirements

R1. The Transmission Owner shall document, maintain, and publish facility connection requirements that at a minimum meet the Intertie Management Committee's facility connection requirements and ensure compliance with its Reliability Standards and applicable Regional Reliability Organization, subregional, 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, and the Railbelt Reliability Committee on request (five business days).

C. Measures

M1. The Transmission Owner shall make available to the Intertie Management Committee for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-0_R1.

M2. The Transmission Owner shall make available to the Intertie Management Committee for inspection evidence that it met all requirements stated in Reliability Standard AKFAC-001-0_R2.

M3. The Transmission Owner shall make available to the Intertie Management Committee for inspection evidence that it met all the requirements stated in Reliability Standard AKFAC-001-0_R3.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: IMC- Regional Reliability Organization.

1.2. 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

1. None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Alaska Standard AKFAC-002-0 — Coordination of Plans for New Facilities

A. Introduction

1. **Title:** **Coordination of Plans For New Generation, Transmission, and End User Facilities**

2. **Number:** AKFAC-002-0

3. **Purpose:**

   To avoid adverse impacts on reliability, Generator Owners and Transmission Owners and electricity end-users must meet facility connection and performance requirements. These requirements are spelled out in detail in The Railbelt Standards for Generation and Transmission Interconnection. 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:** TBD

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 Intertie Management Committee'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 Regional Reliability Organization(s) and the Railbelt Reliability Committee 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

Compliance Monitor: IMC/RRO.

1.2. 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

1. None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Alaska Standard AKRES-001-0 — Reserve Obligation and Allocation

A. Introduction

1. **Title:** **Reserve Obligation and Allocation**
2. **Number:** **AK**RES-001-0
3. **Purpose:**
   This standard describes Reserve Obligations for all Entities interconnected to the Railbelt Grid.
4. **Applicability:**
   - **4.1.** Balancing Authorities
   - **4.2.** Load Serving Entities
   - **4.3.** Generation Owners (Generation Asset Owning Entities)
5. **Effective Date:** TBD

B. Requirements

R1. Reserve Capacity Requirement

R1.1. Each Load Serving Entity is expected to maintain responsibility to provide capacity for its own firm load. As part of such responsibility, 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 projected Annual System Demand 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 Intertie Management Committee (IMC)

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

R2. Responsibility for Operating Reserve

R2.1. Each Load Serving Entity and/or Generation Owner shall provide, or contract for, Spinning Reserve and Non-Spinning Reserve as required by Section R3 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. Operating Reserves, Operating Reserve Obligation, System Reserve Basis and allocation calculations may be modified or changed by the Intertie Management Committee.

R2.3. The System Reserve Basis (SRB) is equal to the Largest Generating Unit Contingency of the system or other such value as determined by engineering studies and approved by the IMC.

R3. Total Reserve Obligation

R3.1. The Total Operating Reserve Obligation at any time shall be an amount equal to 150 percent of the SRB 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 SRB.

R3.3. The balance of the Total Operating Reserve Obligation shall be maintained with Non-Spinning Reserve (aka Non-Operating Reserves).

R4. Generating Unit Capability-

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

R4.1. It shall not be less that the load 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, or quickly, through action of automatic governor controls.

R4.3. The criteria specified in this section may be modified or changed by the Intertie Management Committee.

R5. Allocation of Operating Reserve Obligations

The Operating Reserve Obligation of an Obligated Entity shall be that percentage of the Total Operating Reserve obligation determined by the IMC in accordance with the formulas described in R5 through R7

R5.1. An Entities' Spinning Reserve shall be calculated at any given instant as the difference between the sum of the net 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

R5.2. An Entities' Spinning Reserve may be satisfied by an automatically controlled load shedding program. 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 IMC shall review and approve the Entities' load shedding program that will be used to satisfy its Spinning Reserve requirements.

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. Whenever an entity is unable to meet its Operating Reserve Obligation, that entity will, within two

hours, advise its Balancing Authority and make arrangements to restore its Operating Reserve Obligation.

R5.4. Prudent Utility Practices shall be followed in distributing Operating Reserve, taking into account effective utilization of capacity in an emergency, Response Rate, 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.

R5.5. Subject to R5.3 above, an entity may arrange for one or more other entities to supply part of, or its entire, Operating Reserve requirement.

R5.6. By mutual agreement between the parties, an Entity which has contracted or leased *all* of the Interconnected Value of a Generating Asset or Share of a Generating Asset (energy, capacity, reactive-output dispatch-ability etc.) to another Railbelt Entity, such that this particular asset appears for all intents and purposes as Generating Asset of the Lessee's (contractee's) fleet, may have that asset counted among the Lessee's generating units and the Lessee may include this unit as any other in the Lessee's fleet for purposes of calculation operating reserve allocation.

An example of this is the Bradley Lake Project. AEA and at various times other project participants have contracted to have the Interconnected Value of this Generating Asset or their respective Shares of this Generating Asset assigned to one another in different forms. In each case the assignor has been relieved of the assigned project share (as the assignor's potential LSGC) and that share has been assigned to the assignee's fleet.

R5.7. In an emergency, any Generator Owner, upon request by its Balancing Authority (either through automated frequency or voltage feedback or via System Operator intervention), shall supply to such Balancing Authority part or all of its Operating Reserve up to the full amount of its Available Accredited Capacity. An Entity experiencing an emergency is not required to maintain its Operating Reserve Obligation. There shall be no obligation of an 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 as required by Section R6.2 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 BA may then utilize their reserve as required during the course of the day. If a BA exhausts its Regulating Reserve, they are 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. *Regulating Reserve Obligation*- the Regulating Reserve Obligation for each Balancing Authority shall initially be set by the Intertie Management Committee and shall be allocated amongst eligible Entities' within a Balancing Authority using the same algorithms as that for Spinning Reserve.

R6.3. On an annual basis, after the year end CPS statistics are compiled, the IMC shall modify each Balancing Authorities' Regulating Reserve by increasing/decreasing its current Regulating Reserve by the % deviation in its CPS1. The Regulating Reserve obligations so calculated will be rounded up to the nearest integer MW.

R6.4. The IMC reserves the right to increase/decrease a BAL's Regulating Reserve or require other measures at any time due to changes in the system or repeat infractions.

R7. Spinning Reserve Components

R7.1. Spinning Reserve Obligation will be allocated to an Entity based on the Entities' Largest Single Generating Contingency (including any combination of units with a single point of interconnection forming a single contingency. RAS applications which have been field demonstrated to successfully mitigate the LSGC and have been approved by the IMC may be applied to reduce the magnitude of the LSGC.

R7.2. *Spinning Reserve Largest Contingency Ratio (SRLCR)*: This component shall be calculated as the ratio of an individual Entities' Largest Single Generating Contingency (LSGC) as compared to the sum of the LSGC's of all the Railbelt Entities.

R7.3. The Largest Single Generating Contingency will be based on the maximum Declared Capability of those unit(s) subject to the single contingency (regardless of RAS applications; when operated at the temperature corresponding to the average monthly temperature for that region.

An example of a Generating Contingency is a combined cycle unit; the loss of the combustion turbine will precipitate the loss of both the CT as well as the waste heat unit.

R7.4. If entities share a unit, an entities Share of such a unit could qualify as their LSGC if they have no unit(s) that are larger. This component may change whenever the average monthly temperature changes or an entity installs new generation.

R7.5. However due to variable response time, duct firing may not be counted as spinning reserves. Upon petition, the IMC may approve the inclusion of duct

firing as spinning reserve on a unit-by-unit basis if can be show by field testing (under system limiting conditions) to be equally as responsive as the remainder of the Spinning Reserve contribution of the particular unit(s) it is augmenting. It shall be the obligation of the petitioning entity to seek an approved test plan from the Intertie Management Committee, arrange for, bear the costs of and accomplish such testing. The Intertie Management Committee or its designee shall be present to observe and review documentation of such testing.

R7.6. As bus faults are rare, these elements generally do not constitute a LSGC; however, bus faults or multiple units on a single collector feeder may be considered as an LSGC should the IMC believe reasonable engineering and operating practice dictates that in a particular situation these are a reasonable contingency. A single point of failure in a fuel supply that may result in the loss of multiple units does not necessarily constitute a LSGC. However, subject to the reasoning above, the IMC may exercise judgment in such matters.

R7.7. An entity adding a unit greater than 120 MW will accrue the obligation above 120 MW on a one for one basis in addition to their otherwise calculated spin obligation. The aforementioned 120 MW is subject to change by the IMC.

R7.8. The Spinning Reserve Obligation (SRO) of each Obligated Entity shall be calculated as follows:

$$SRO_e = \{LSGC_e\} / \{\sum_i (LSGC_i)\} * [SRB] + MUD_e$$

e ≡ Obligated Entity

i ≡ All Interconnected Entities

MUD_e=the difference between the R7.7 max unit limit and an entities largest unit if greater than the R7.7 limit.

C. Measures

M1. Each Obligated Entity and Balancing Authority shall maintain:

M1.1. Records of their Reserve Capacity at any point in time. These records will be updated as new Assets are added and other 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.

D. Compliance Monitoring

1. Balancing Authorities
2. IMC-Railbelt Regional Reliability Organization

E. Non-Compliance

Level 1.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Standard AKTPL-001-0 - System Performance Under Normal Conditions

A. Introduction

1. **Title:** **System Performance Under Normal (No Contingency) Conditions (Category A)**

2. **Number:** **AK**TPL-001-0

3. **Purpose:**

   System simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

5. **Effective Date:** TBD

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that, with all transmission facilities in service and with normal (pre-contingency) operating procedures in effect, the Network can be operated to supply projected customer demands and projected Firm (non- recallable reserved) Transmission Services at all Demand levels over the range of forecast system demands, under the conditions defined in Category A of Table I. To be considered valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made every two years.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category A of Table 1 (no contingencies). The specific elements selected (from each of the following categories) shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Cover critical system conditions and study years as deemed appropriate by the entity performing the study.

R1.3.2. Be conducted annually unless changes to system conditions do not warrant such analyses.

R1.3.3. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.4. Have established normal (pre-contingency) operating procedures in place.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed for selected demand levels over the range of forecast system demands.

R1.3.7. Demonstrate that system performance meets Table 1 for Category A (no contingencies).

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category A.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard AKTPL-001-1_R1, the Planning Authority and Transmission Planner shall each:

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. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.2. Provide to the System operator a written summary of the scenario and if practical recommended operating guidelines to mitigate the cause and/or effect of scenario until such time as a permanent solution can be achieved.

R2.3. Review, in subsequent assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these reliability assessments and corrective plans and shall provide these to its respective Regional Reliability Organization(s) if requested.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard AKTPL-001-1_R2.1 and AKTPL-001-1_R2.3.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its Reliability Assessments and corrective plans per Reliability Standard AKTPL-001-1_R2.2 and R3 if the plans were requested.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: IMC/ Regional Reliability Organization.

Each Compliance Monitor shall report compliance and violations to the RRC.

1.2. Compliance Monitoring Period and Reset Timeframe

Every two years.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements. removed or Cascading out of service.	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 5. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Alaska Standard AKTPL-002-0 - System Performance Following Loss of a Single BES Element and Likely Subsequent Contingencies

A. Introduction

1. **Title:** **System Performance Following Loss of a Single Bulk Electric System Element (Category B) and Likely Subsequent Contingencies**

2. **Number:** **AK**TPL-002-0

3. **Purpose:**

   Given the limited robustness of the Railbelt Electric Grid and the relatively lean nature of transmission investment in the Grid, system simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

   In instances where capital construction costs are beyond the current means of the Railbelt Interconnection, challenges to reliability must be well understood and to the degree practical mitigation strategies must be developed to maximize system performance and reliability within the range of existing assets or within the range of assets within the near terms means of the Railbelt Interconnection.

   Further, system operators must be made aware of potential pitfalls in operating scenarios which can lead to significant disruptions in electric service.

4. **Applicability:**

   4.1. Planning Authority

   4.2. Transmission Planner

   4.3. Load Balancing Authorities

   4.4. System Operators

5. **Effective Date:** TBD

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned such that the Network can be operated to supply projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand levels over the range of forecast system demands, under the contingency conditions as defined in Category B of Table I. The loss of no single element of the BES should result in the loss of firm load or firm transfers. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Be made every two years.

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories,, showing system performance

following Category B of Table 1 (single contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category B contingencies that would produce the more severe System results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted biannually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system Demands.

R1.3.7. Demonstrate that system performance meets Category B contingencies.

R1.3.8. Include existing and planned facilities.

R1.3.9. Include Reactive Power resources to ensure that adequate reactive resources are available to meet system performance.

R1.3.10. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.11. Include the effects of existing and planned control devices.

R1.3.12. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those demand levels for which planned (including maintenance) outages are performed.

R1.3.13. For the near-term (years one through five) under the contingencies conditions above, shall define the thermal and stability limit of each transmission line within each LBA and each LBA interconnection.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category B of Table I.

R1.5. Consider all contingencies applicable to Category B and any probable or likely Category C and D Sub contingencies. Further the most severe of the C& D contingencies in terms of loss of load, frequency recovery, and voltage recovery shall be identified

R2. When System simulations indicate an inability of the systems to respond as prescribed in Reliability Standard AKTPL-002-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of its plans to achieve the required system performance as described above throughout the planning horizon and provide a written summary of the particular scenario with recommended operating procedures to avoid event triggers:

R1.5.1. Including a schedule for implementation.

R1.5.2. Including a discussion of expected required in-service dates of facilities.

R1.5.3. Consider lead times necessary to implement plans.

R1.6. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of its Reliability Assessments and corrective plans and shall bi-annually provide the results to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

R4. Bi –annually the relevant scenarios will be reviewed with Balancing Authorities and System Operators to alert them to potential pitfalls in daily operating plans and to assist in development of system restoration procedures. Documentation regarding which scenarios are considered relevant and which are not considered relevant will be kept by the Panning Authority and Transmission Planner.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard AKTPL-002-0_R1 and AKTPL-002-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard AKTPL-002-0_R3 and R4

M3. The Load Balancing Authority and System Operator shall have records of the implementation of risk mitigation strategies and systems.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.
Each Compliance Monitor shall report compliance and violations to IMC via Compliance Reporting Process.

1.2. Compliance Monitoring Period and Reset Timeframe

Annually.

1.3. Data Retention

None specified.

1.4. Additional Compliance Information

None.

2. Levels of Non-Compliance

2.1. Level 1: Not applicable.

2.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

2.3. Level 3: Not applicable.

2.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available.

E. Regional Differences

1. None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Alaska Standard AKTPL-003-0 — System Performance Following Loss of Two or More BES Elements

A. Introduction

1. Title: **System Performance Following Loss of Two or More Bulk Electric System Elements (Category C&D)**

2. Number: AKTPL-003-0

3. Purpose:

Given the limited robustness of the Railbelt Electric Grid and the relatively lean nature of transmission investment in the Grid, system simulations and associated assessments are needed periodically to ensure that reliable systems are developed that meet specified performance requirements with sufficient lead time, and continue to be modified or upgraded as necessary to meet present and future system needs.

In instances where capital construction costs are beyond the current means of the Railbelt Interconnection, challenges to reliability must be well understood and to the degree practical mitigation strategies must be developed to maximize system performance and reliability within the range of existing assets or within the range of assets within the near terms means of the Railbelt Interconnection.

Further, system operators must be apprised of the existing weaknesses in the system, scenarios which can initiate large scale loss of load and possible cascading outages. Finally operations mitigation plans and systems must be developed and put into place to minimize risk and maximize reliability until assets can be constructed to relieve system weaknesses.

4. Applicability:

4.1. Planning Authority

4.2. Transmission Planner

4.3. Load Balancing Authority

4.4. System operator

5. Effective Date: TBD

B. Requirements

R1. The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment which portions of the interconnected transmission systems can be operated to supply which portions of projected customer demands and projected Firm (non-recallable reserved) Transmission Services, at all demand Levels over the range of forecast system demands, under the contingency conditions as defined in Category C and D of Table I (attached). The controlled interruption of customer Demand, the planned removal of generators, or the Curtailment of firm (non-recallable reserved) power transfers may be necessary to meet this standard. To be valid, the Planning Authority and Transmission Planner assessments shall:

R1.1. Shall be made as required by the IMC

R1.2. Be conducted for near-term (years one through five) and longer-term (years six through ten) planning horizons.

R1.3. Be supported by a current or past study and/or system simulation testing that addresses each of the following categories, showing system performance following Category C and D of Table 1 (multiple contingencies). The specific elements selected (from each of the following categories) for inclusion in these studies and simulations shall be acceptable to the associated Regional Reliability Organization(s).

R1.3.1. Be performed and evaluated only for those Category C &D contingencies that would produce the more severe system results or impacts. The rationale for the contingencies selected for evaluation shall be available as supporting information. An explanation of why the remaining simulations would produce less severe system results shall be available as supporting information.

R1.3.2. Cover critical system conditions and study years as deemed appropriate by the responsible entity.

R1.3.3. Be conducted bi-annually unless changes to system conditions do not warrant such analyses.

R1.3.4. Be conducted beyond the five-year horizon only as needed to address identified marginal conditions that may have longer lead-time solutions.

R1.3.5. Have all projected firm transfers modeled.

R1.3.6. Be performed and evaluated for selected demand levels over the range of forecast system demands.

R1.3.7. Include existing and planned facilities.

R1.3.8. Include Reactive Power resources to ensure that adequate reactive resources are available to meet System performance.

R1.3.9. Include the effects of existing and planned protection systems, including any backup or redundant systems.

R1.3.10. Include the effects of existing and planned control devices.

R1.3.11. Include the planned (including maintenance) outage of any bulk electric equipment (including protection systems or their components) at those Demand levels for which planned (including maintenance) outages are performed.

R1.4. Address any planned upgrades needed to meet the performance requirements of Category C and D.

R1.5. Consider all contingencies applicable to Category C and D.

R2. When system simulations indicate an inability of the systems to respond as prescribed in Reliability Standard AKTPL-003-0_R1, the Planning Authority and Transmission Planner shall each:

R2.1. Provide a written summary of the particular scenario, recommended operating procedures to avoid event triggers and plans to achieve the required system performance as described above throughout the planning horizon:

R2.1.1. Including a schedule for implementation.

R2.1.2. Including a discussion of expected required in-service dates of facilities.

R2.1.3. Consider lead times necessary to implement plans.

R2.1.4. Provide summary to Load Balancing Authorities (LBA)/ System Operators, obtain feedback, and assist in LBA's development of risk mitigation strategies and systems.

R2.1.5. Implement the strategies and systems of R 2.1.4

R2.2. Review, in subsequent annual assessments, (where sufficient lead time exists), the continuing need for identified system facilities. Detailed implementation plans are not needed.

R3. The Planning Authority and Transmission Planner shall each document the results of these Reliability Assessments and corrective plans and shall annually provide these to its respective Regional Reliability Organization(s), as required by the Regional Reliability Organization.

R4. Bi –annually the relevant scenarios will be reviewed with Balancing Authorities and System Operators to alert them to potential pitfalls in daily operating plans and to assist in development of system restoration procedures. Documentation regarding which scenarios are considered relevant and which are not considered relevant will be kept by the Panning Authority and Transmission Planner.

C. Measures

M1. The Planning Authority and Transmission Planner shall have a valid assessment and corrective plans as specified in Reliability Standard AKTPL-003-0_R1 and AKTPL-003-0_R2.

M2. The Planning Authority and Transmission Planner shall have evidence it reported documentation of results of its reliability assessments and corrective plans per Reliability Standard AKTPL-003-0_R3 and R4

M3. The Load Balancing Authority and System Operator shall have records of the implementation of risk mitigation strategies and systems.

D. Compliance

1. Compliance Monitoring Process

2. Compliance Monitoring Responsibility

Compliance Monitor: Regional Reliability Organizations.

2.1. Compliance Monitoring Period and Reset Timeframe

Bi-annually.

2.2. Data Retention

None specified.

2.3. Additional Compliance Information

None.

3. Levels of Non-Compliance

3.1. Level 1: Not applicable.

3.2. Level 2: A valid assessment and corrective plan for the longer-term planning horizon is not available.

3.3. Level 3: Not applicable.

3.4. Level 4: A valid assessment and corrective plan for the near-term planning horizon is not available. Practical risk mitigations strategies and systems have not been developed implemented and documented.

E. Regional Differences

4. None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

Table I. Transmission System Standards – Normal and Emergency Conditions

Category	Contingencies	System Limits or Impacts		
	Initiating Event(s) and Contingency Element(s)	System Stable and both Thermal and Voltage Limits within Applicable Rating [a]	Loss of Demand or Curtailed Firm Transfers	Cascading [c] Outages
A No Contingencies	All Facilities in Service	Yes	No	No
B Event resulting in the loss of a single element.	Single Line Ground (SLG) or 3-Phase (3Ø) Fault, with Normal Clearing: 1. Generator 2. Transmission Circuit 3. Transformer Loss of an Element without a Fault.	Yes Yes Yes Yes	No [b] No [b] No [b] No [b]	No No No No
	Single Pole Block, Normal Clearing [e]: 4. Single Pole (dc) Line	Yes	No [b]	No
C Event(s) resulting in the loss of two or more (multiple) elements.	SLG Fault, with Normal Clearing [e]: 1. Bus Section 2. Breaker (failure or internal Fault)	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG or 3Ø Fault, with Normal Clearing [e], Manual System Adjustments, followed by another SLG or 3Ø Fault, with Normal Clearing [e]: 3. Category B (B1, B2, B3, or B4) contingency, manual system adjustments, followed by another Category B (B1, B2, B3, or B4) contingency	Yes	Planned/ Controlled [c]	No
	Bipolar Block, with Normal Clearing [e]: 4. Bipolar (dc) Line Fault (non 3Ø), with Normal Clearing [e]: 5. Any two circuits of a multiple circuit towerline [f]	Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c]	No No
	SLG Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 6. Generator 7. Transformer 8. Transmission Circuit 9. Bus Section	Yes Yes Yes Yes	Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c] Planned/ Controlled [c]	No No No No

D [d] Extreme event resulting in two or more (multiple) elements removed or Cascading out of service	3Ø Fault, with Delayed Clearing [e] (stuck breaker or protection system failure): 1. Generator 2. Transmission Circuit 3. Transformer 4. Bus Section 3Ø Fault, with Normal Clearing [e]: 6. Breaker (failure or internal Fault) 6. Loss of towerline with three or more circuits 7. All transmission lines on a common right-of way 8. Loss of a substation (one voltage level plus transformers) 9. Loss of a switching station (one voltage level plus transformers) 10. Loss of all generating units at a station 11. Loss of a large Load or major Load center 12. Failure of a fully redundant Special Protection System (or remedial action scheme) to operate when required 13. Operation, partial operation, or misoperation of a fully redundant Special Protection System (or Remedial Action Scheme) in response to an event or abnormal system condition for which it was not intended to operate 14. Impact of severe power swings or oscillations from Disturbances in another Regional Reliability Organization.	Evaluate for risks and consequences. ▪ May involve substantial loss of customer Demand and generation in a widespread area or areas. ▪ Portions or all of the interconnected systems may or may not achieve a new, stable operating point. ▪ Evaluation of these events may require joint studies with neighboring systems.

a) Applicable rating refers to the applicable Normal and Emergency facility thermal Rating or system voltage limit as determined and consistently applied by the system or facility owner. Applicable Ratings may include Emergency Ratings applicable for short durations as required to permit operating steps necessary to maintain system control. All Ratings must be established consistent with applicable NERC Reliability Standards addressing Facility Ratings.

b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.

c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (non-recallable reserved) electric power transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

d) A number of extreme contingencies that are listed under Category D and judged to be critical by the transmission planning entity(ies) will be selected for evaluation. It is not expected that all possible facility outages under each listed contingency of Category D will be evaluated.

e) Normal clearing is when the protection system operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Delayed clearing of a Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay.

f) System assessments may exclude these events where multiple circuit towers are used over short distances (e.g., station entrance, river crossings) in accordance with Regional exemption criteria.

Alaska Standard AKVAR-001-0— Voltage and Reactive Control

A. Introduction

1. **Title:** **Voltage and Reactive Control**
2. **Number:** VAR-001-0
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:** TBD

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).

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[1] The voltage schedule is a target voltage to be maintained within a tolerance band during a specified period.

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 IROL or 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.

D. Compliance

1. Compliance Monitoring Process

1.1. Compliance Monitoring Responsibility

IMC-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.

(a) Levels of Non-Compliance

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

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

(i) No evidence to show that directives were issued in accordance with R6.1.

(ii) 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.

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

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

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

D. Regional Difference

None identified.

Version History

Version	Date	Action	Change Tracking
001	11-1-2013	Approved -IMC	

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

A. Introduction

1. Title: Generator Operation for Maintaining Network Voltage Schedules

2. Number: VAR-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: TBD

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 Ratings[2]) 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.

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[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

IMC-Regional Reliability Organization.

1.2. 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 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
001	11-1-2013	Approved -IMC	

Exhibit A

The following tables (1-4) layout the proposed 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 proposed future operating plans of the Railbelt Utilites.

A separate table has been developed for each of the years 2013 through post 2015:

- Table-1 2013 System today
- Table-2 2014 System 1/1/2014
- Table-3 2015 System
- Table-4 Post 2015 system with ISO or RTO named ERCOA

The terms and Entity functional assignments found in the left column entitled "Entity Function" are found throughout the Final Draft of the Railbelt Reliability Standards and are defined in the Railbelt Regional Reliability Standards Glossary.

Legend	
Current Year assignements	
Changes over Prior year	
Participation in planning through standards development working groups	

Table T1-2013

Entity Function	GVEA	Aurora	Doyon/DOD	Usebelli	IMC	MEA	CEA	AML&P	SES	HEA	BPMC	AEA	RCA
Balancing Authority													
Compliance Enforcement Authority													
Compliance Monitor													
Distribution Provider													
Generator Operator													
Generator Owner *													
Interchange Authority													
Load-Serving Entity													
Market Operator (Resource Integrator)													
Obligated Entity													
Reliability Coordinator													
Planning Authority													
Purchasing-Selling Entity													
Reliability Assurer													
Resource Planner													
Standards Developer													
Transmission Operator													
Transmission Owner													
Transmission Planner													
Transmission Service Provider													

Table T2-2014

Entity Function	GVEA	Aurora	Doyon/DOD	Usebelli	IMC	MEA	CEA	AML&P	SES	HEA	BPMC	AEA	RCA
Balancing Authority													
Compliance Enforcement Authority													
Compliance Monitor													
Distribution Provider													
Generator Operator													
Generator Owner *													
Interchange Authority													
Load-Serving Entity													
Market Operator (Resource Integrator)													
Obligated Entity													
Reliability Coordinator													
Planning Coordinator													
Purchasing-Selling Entity													
Reliability Assurer													
Resource Planner													
Standards Developer													
Transmission Operator													
Transmission Owner													
Transmission Planner													
Transmission Service Provider													
Generation Planner													

Table T3-2015

Entity Function	GVEA	Aurora	Doyon/DOD	Usebelli	IMC	MEA	CEA	AML&P	SES	HEA	BPMC	AEA	RCA
Balancing Authority													
Compliance Enforcement Authority													
Compliance Monitor													
Distribution Provider													
Generator Operator													
Generator Owner *													
Interchange Authority													
Load-Serving Entity													
Market Operator (Resource Integrator)													
Obligated Entity													
Reliability Coordinator													
Planning Coordinator													
Purchasing-Selling Entity													
Reliability Assurer													
Resource Planner													
Standards Developer													
Transmission Operator													
Transmission Owner													
Transmission Planner													
Transmission Service Provider													
Generation Planner													

Railbelt Regional Reliability Standards

Glossary of Terms Used in Railbelt Reliability Standards

Updated May 29, 2013

Introduction:

This Glossary lists terms that are used in The Railbelt Reliability, Operating, Planning, and Interconnection standards. Further these terms are used in the general lexicon of Railbelt planning and operations. The source document s for this Glossary are defined for use in one or more of North American Reliability Corporation's (NERC) Railbelt or Regional Reliability Standards and adopted by the NERC Board of Trustees from February 8, 2005 through May 9, 2013. In some cases these definitions of the terms have been edited and modified to reflect the standards and practices in use in the Alaskan Railbelt.

For reference or a historical understanding of the development the terminology one should reference the NERC "Glossary of Terms Used in NERC Reliability Standards dated May 9th, 2013". *Most of the terms* identified in this glossary were adopted as part of the development of NERC's initial set of reliability standards, called the "Version 0" standards. Subsequent to the development of Version 0 standards, new definitions have been developed and approved following NERC's Reliability Standards Development Process, and added to that glossary following board adoption. Subsequently many of these terms have been approved by FERC.

Definitions that have been adopted by the NERC Board of Trustees but have not been approved by FERC, or FERC has not approved but has directed be modified, are shaded in blue. Definitions that have been remanded or retired are shaded in orange.

Definitions:

A.....1

B.....4

C.....9

D 14

E 17

F 19

G 23

H.....24

I.....25

L 29

M 30

N.....31

O 33

P 36

R.....40

S.....47

T 50

V.....54

W.....54

Y 54

Railbelt Regional Reliability Standards

Railbelt Term	Acronym	Term Approved	Definition
Accredited Capacity			The capacity of a generating unit or group of generating units with a single point of interconnection to the Railbelt. Determined by the Intertie Management Committee or it's designee. Used in determining Reserve Capacity Obligation and Total Operating Reserve requirement
Adequacy			The ability of the electric system to supply the aggregate electrical demand and energy requirements of the end-use customers at all times, taking into account scheduled and reasonably expected unscheduled outages of system elements.
Adjacent Balancing Authority			A Balancing Authority Area that is interconnected another Balancing Authority Area either directly or via a multi-party agreement or transmission tariff.
Adverse Reliability Impact			The impact of an event that results in frequency-related instability; voltage collapse; unplanned tripping of load or generation; or uncontrolled separation or cascading outages that affects a widespread area of the Interconnection.
Adverse Reliability Impact			The impact of an event that results in Bulk Electric System instability or Cascading.
After the Fact	ATF		A time classification assigned to an RFI when the submittal time is greater than one hour after the start time of the RFI.
Agreement			A contract or arrangement, either written or verbal and sometimes enforceable by law.
Alternative Interpersonal Communication			Any Interpersonal Communication that is able to serve as a substitute for, and does not utilize the same infrastructure (medium) as, Interpersonal Communication used for day-to- day operation.

Railbelt Term	Acronym	Term Approved	Definition
Altitude Correction Factor			A multiplier applied to specify distances, which adjusts the distances to account for the change in relative air density (RAD) due to altitude from the RAD used to determine the specified distance. Altitude correction factors apply to both minimum worker approach distances and to minimum vegetation clearance distances.
Ancillary Service			Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Service Provider's transmission system in accordance with good utility practice. (*From FERC order 888-A.*)
Anti-Aliasing Filter			An analog filter installed at a metering point to remove the high frequency components of the signal over the AGC sample period.
Area Control Error	ACE		The instantaneous difference between a Balancing Authority's net actual and scheduled interchange, if taking into account the effects of Frequency Bias, correction for meter error, and Automatic Time Error Correction term is abbreviated (ATEC).
Area Interchange Methodology			The Area Interchange methodology is characterized by determination of incremental transfer capability via simulation, from which Total Transfer Capability (TTC) can be mathematically derived. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from the TTC, and Postbacks and counterflows are added, to derive Available Transfer Capability. Under the Area Interchange Methodology, TTC results are generally reported on an area to area basis.

Railbelt Term	Acronym	Approval Date	Definition
Arranged Interchange			The state where the Interchange Authority has received the Interchange information (initial or revised).
Automatic Generation Control	AGC		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 Flowgate Capability	AFC		A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows.
Available Transfer Capability	ATC		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.
Available Transfer Capability Implementation Document	ATCID		A document that describes the implementation of a methodology for calculating ATC or AFC, and provides information related to a Transmission Service Provider's calculation of ATC or AFC.
ATC Path			Any combination of Point of Receipt and Point of Deliver for which ATC is calculated; and any Posted Path[1].

[1] See 18 CFR 37.6(b)(1)

	Railbelt Term	Acronym	Approved Date	Definition
R	Balancing Authority (Load Balancing Authority)	BA (LBA)		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.
R	Balancing Authority Area (Load Balancing Area)			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.
	Base Load			The minimum amount of electric power delivered or required over a given period at a constant rate.
	BES Cyber Asset			A Cyber Asset that if rendered unavailable, degraded, or misused would, within 15 minutes of its required operation, misoperation, or non-operation, adversely impact one or more Facilities, systems, or equipment, which, if destroyed, degraded, or otherwise rendered unavailable when needed, would affect the reliable operation of the Bulk Electric System. Redundancy of affected Facilities, systems, and equipment shall not be considered when determining adverse impact. Each BES Cyber Asset is included in one or more BES Cyber Systems. (A Cyber Asset is not a BES Cyber Asset if, for 30 consecutive calendar days or less, it is directly connected to a network within an ESP, a Cyber Asset within an ESP, or to a BES Cyber Asset, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.)

Railbelt Term	Acronym	Approved Date	Definition
BES Cyber System			One or more BES Cyber Assets logically grouped by a responsible entity to perform one or more reliability tasks for a functional entity.
BES Cyber System Information			Information about the BES Cyber System that could be used to gain unauthorized access or pose a security threat to the BES Cyber System. BES Cyber System Information does not include individual pieces of information that by themselves do not pose a threat or could not be used to allow unauthorized access to BES Cyber Systems, such as, but not limited to, device names, individual IP addresses without context, ESP names, or policy statements. Examples of BES Cyber System Information may include, but are not limited to, security procedures or security information about BES Cyber Systems, Physical Access Control Systems, and Electronic Access Control or Monitoring Systems that is not publicly available and could be used to allow unauthorized access or unauthorized distribution; collections of network addresses; and network topology of the BES Cyber System.
Blackstart Capability Plan			A documented procedure for a generating unit or station to 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.
Blackstart Resource			A generating unit(s) and its associated set of equipment which has the ability to be started without support from the System or is designed to remain energized without connection to the remainder of the System, with the ability to energize a bus, meeting the Transmission Operator's restoration plan needs for real and reactive power capability, frequency and voltage control, and that has been included in the Transmission Operator's restoration plan.
Block Dispatch			A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, the capacity of a given generator is segmented into loadable "blocks," each of which is grouped and ordered relative to other blocks (based on characteristics including, but not limited to, efficiency, run of river or fuel supply considerations, and/or "must-run" status).

	Railbelt Term	Acronym	Approved Date	Definition
R	Bulk Electric System	BES		As defined by the 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.
R	Bulk Electric System	BES		Unless modified by the lists shown below, all Transmission Elements operated at 69 kV or higher and Real Power and Reactive Power resources used to control transmission quantities. This does not include facilities used in the local distribution of electric energy. **Inclusions:** **I1** - Transformers with the primary terminal and at least one secondary terminal operated at 69 kV or higher unless excluded under Exclusion E1 or E3. **I2** - Generating resource(s) with gross individual nameplate rating greater than 5 MVA or gross plant/facility aggregate nameplate rating greater than 10 MVA including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 69 kV or above. **I3** - Blackstart Resources identified in the Transmission Operator's restoration plan. **I4** - Dispersed power producing resources with aggregate capacity greater than 5 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 30 kV or above.

	Railbelt Term	Acronym	Approved Date	FERC Approved Date	Definition
R	Bulk Electric System **(Continued)**	BES			**I5** –Static or dynamic devices (excluding generators) dedicated to supplying or absorbing Reactive Power that are connected at 69 kV or higher, or through a dedicated transformer with a high-side voltage of 69 kV or higher, or through a transformer that is designated in Inclusion I1.
					E1 - A generating unit or multiple generating units on the customer's side of the retail meter that serve all or part of the retail Load with electric energy if: (i) the net capacity provided to the BES does not exceed 5 MVA, and (ii) standby, back-up, and maintenance power services are provided to the generating unit or multiple generating units or to the retail Load by a Balancing Authority, or provided pursuant to a binding obligation with a Generator Owner or Generator Operator, or under terms approved by the applicable regulatory authority.
					E2 – Reactive Power devices owned and operated by the retail customer solely for its own use. Note - Elements may be included or excluded on a case-by-case basis through the Rules of Procedure exception process.

Railbelt Term	Acronym	Approved Date	Definition
Bulk-Power System			A) Facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability. The term does not include facilities used in the local distribution of electric energy.
Burden			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 NERC, Regional Reliability Organization, or local operating reliability standards or criteria.
Business Practices			Those business rules contained in the Transmission Service Provider's applicable tariff, rules, or procedures; associated Regional Reliability Organization or regional entity business practices; or NAESB Business Practices.
Bus-tie Breaker			A circuit breaker that is positioned to connect two individual substation bus configurations.

Railbelt Term	Acronym	Approved Date	Definition
Capacity Benefit Margin	CBM		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.
Capacity Benefit Margin Implementation Document	CBMID		A document that describes the implementation of a Capacity Benefit Margin methodology.
Capacity Emergency			A capacity emergency exists when a Balancing Authority Area's operating capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements.
Cascading			The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies.
Cascading Outages			The uncontrolled successive loss of Bulk Electric System Facilities triggered by an incident (or condition) at any location resulting in the interruption of electric service that cannot be restrained from spreading beyond a pre- determined area.

	Railbelt Term	Acronym	Approved Date	Definition
R	Critical Infrastructure Protection (CIP) Exceptional Circumstance			A situation that involves or threatens to involve one or more of the following, or similar, conditions that impact safety or BES reliability: a risk of injury or death; a natural disaster; civil unrest; an imminent or existing hardware, software, or equipment failure; a Cyber Security Incident requiring emergency assistance; a response by emergency services; the enactment of a mutual assistance agreement; or an impediment of large scale workforce availability.
	CIP Senior Manager			A single senior management official with overall authority and responsibility for leading and managing implementation of and continuing adherence to the requirements within the Railbelt CIP Standards, (To be developed).
	Clock Hour			The 60-minute period ending at :00. All surveys, measurements, and reports are based on Clock Hour periods unless specifically noted.
	Cogeneration			Production of electricity from steam, heat, or other forms of energy produced as a by-product of another process.
	Compliance Monitor			The entity that monitors, reviews, and ensures compliance of responsible entities with reliability standards.
	Compliance Enforcement Authority			Entity with Statutory power to enforce operating and Planning Standards and enforce the findings of the Compliance Monitor
	Confirmed Interchange			The state where the Interchange Authority has verified the Arranged Interchange.

Railbelt Term	Acronym	Approved Date	Definition
Congestion Management Report			A report that the Interchange Distribution Calculator issues when a Reliability Coordinator initiates the Transmission Loading Relief procedure. This report identifies the transactions and native and network load curtailments that must be initiated to achieve the loading relief requested by the initiating Reliability Coordinator.
Consequential Load Loss			All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.
Constrained Facility			A transmission facility (line, transformer, breaker, etc.) that is approaching, is at, or is beyond its System Operating Limit or Interconnection Reliability Operating Limit.
Contingency			The unexpected failure or outage of a system component, such as a generator, transmission line, circuit breaker, switch or other electrical element.
Contingency Reserve			The provision of capacity deployed by the Balancing Authority to meet the Disturbance Control Standard (DCS) and other Regional Reliability Organization contingency requirements.
Contract Path			An agreed upon electrical path for the continuous flow of electrical power between the parties of an Interchange Transaction.
Control Center			One or more facilities hosting operating personnel that monitor and control the Bulk Electric System (BES) in real- time to perform the reliability tasks, including their associated data centers, of: 1) a Reliability Coordinator, 2) a Balancing Authority, 3) a Transmission Operator for transmission Facilities at two or more locations, or 4) a Generator Operator for generation Facilities at two or more locations.

Railbelt Term	Acronym	Approved Date	Definition
Control Performance Standard	CPS		The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.
Corrective Action Plan			A list of actions and an associated timetable for implementation to remedy specific problem.
Cranking Path			A portion of the electric system that can be isolated and then energized to deliver electric power from a generation source to enable the startup of one or more other generating units.
Critical Assets			Facilities, systems, and equipment which, if destroyed, degraded, or otherwise rendered unavailable, would affect the reliability or operability of the Bulk Electric System.
Critical Cyber Assets			Cyber Assets essential to the reliable operation of Critical Assets.
Curtailment			A reduction in the scheduled capacity or energy delivery of an Interchange Transaction.
Curtailment Threshold			The minimum Transfer Distribution Factor which, if exceeded, will subject an Interchange Transaction to curtailment to relieve a transmission facility constraint.

Railbelt Term	Acronym	Approved Date	Definition
Cyber Assets			Programmable electronic devices and communication networks including hardware, software, and data.
Cyber Assets			Programmable electronic devices, including the hardware, software, and data in those devices.
Cyber Security Incident			Any malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical Security Perimeter of a Critical Cyber Asset, or, • Disrupts, or was an attempt to disrupt, the operation of a Critical Cyber Asset.
Cyber Security Incident			A malicious act or suspicious event that: • Compromises, or was an attempt to compromise, the Electronic Security Perimeter or Physical SecurityPerimeter or, • Disrupts, or was an attempt to disrupt, the operation of a BES Cyber System.

	Railbelt Term	Acronym	Approved Date	Definition
R	Declared Capability			Declared Generating Unit 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. In the case of multiple units connected to the Grid through a single point of interconnection (regardless of RAS applications) the sum of the Declared Generating Unit Capabilities subject to outage of the single point of interconnection.
	Delayed Fault Clearing			Fault clearing consistent with correct operation of a breaker failure protection system and its associated breakers, or of a backup protection system with an intentional time delay.
	Demand			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.
	Demand-Side Management	DSM		The term for all activities or programs undertaken by Load- Serving Entity or its customers to influence the amount or timing of electricity they use.
	Dial-up Connectivity			A data communication link that is established when the communication equipment dials a phone number and negotiates a connection with the equipment on the other end of the link.
	Direct Control Load Management	DCLM		Demand-Side Management that is under the direct control of the system operator. DCLM may control the electric supply to individual appliances or equipment on customer premises. DCLM as defined here does not include Interruptible Demand.
	Dispatch Order			A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, each generator is ranked by priority.

Railbelt Term	Acronym	Approved Date	Definition
Dispersed Load by Substations			Substation load information configured to represent a system for power flow or system dynamics modeling purposes, or both.
Distribution Factor	DF		The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate).
Distribution Provider	DP		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			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		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.

Railbelt Term	Acronym	Approved Date	Definition
Disturbance Monitoring Equipment	DME DSM Tesla		Devices capable of monitoring and recording system data pertaining to a Disturbance. Such devices include the following categories of recorders[2]: • Sequence of event recorders which record equipment response to the event • Fault recorders, which record actual waveform data replicating the system primary voltages and currents. This may include protective relays. • Dynamic Disturbance Recorders (DDRs), which record incidents that portray power system behavior during dynamic events such as low-frequency (0.1 Hz – 3 Hz) oscillations and abnormal frequency or voltage excursions.
Dynamic Interchange Schedule or Dynamic Schedule			A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation 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.
Dynamic Transfer			The provision of the real-time monitoring, telemetering, computer software, hardware, communications, engineering, energy accounting (including inadvertent interchange), and administration required to electronically move all or a portion of the real energy services associated with a generator or load out of one Balancing Authority Area into another.

[2] Phasor Measurement Units and any other equipment that meets the functional requirements of DMEs may qualify as DMEs.

	Railbelt Term	Acronym	Approved Date	Definition
R	Economic Dispatch	EDC		The allocation of demand to individual generating units on line to effect the most economical production of electricity.
	Electronic Access Control or Monitoring Systems			Cyber Assets that perform electronic access control or electronic access monitoring of the Electronic Security Perimeter(s) or BES Cyber Systems. This includes Intermediate Devices.
	Electronic Access Point	EAP		A Cyber Asset interface on an Electronic Security Perimeter that allows routable communication between Cyber Assets outside an Electronic Security Perimeter and Cyber Assets inside an Electronic Security Perimeter.
	Electrical Energy			The generation or use of electric power by a device over a period of time, expressed in kilowatthours (kWh), megawatthours (MWh), or gigawatthours (GWh).
	Electronic Security Perimeter	ESP		The logical border surrounding a network to which Critical Cyber Assets are connected and for which access is controlled.
	Electronic Security Perimeter	ESP		The logical border surrounding a network to which BES Cyber Systems are connected using a routable protocol.
	Element			Any electrical device with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more components.

	Railbelt Term	Acronym	Approved Date	Definition
	Emergency or BES Emergency			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.
R	Emergency Rating			The rating as defined by the equipment owner that specifies the level of electrical loading or output, usually expressed in megawatts (MW) or Mvar or other appropriate units, that a system, facility, or element can support, produce, or withstand for a finite period. The rating assumes acceptable loss of equipment life or other physical or safety limitations for the equipment involved. The rating may reflect thermal capability and sag/terrain conditions, potential stability or out of step conditions related to subsequent events or other limiting conditions.
	Emergency Request for Interchange	Emergency RFI		Request for Interchange to be initiated for Emergency or Energy Emergency conditions.
	Energy Emergency			A condition when a Load-Serving Entity has exhausted all other options and can no longer provide its customers' expected energy requirements.
	Equipment Rating			The maximum and minimum voltage, current, frequency, real and reactive power flows on individual equipment under steady state, short-circuit and transient conditions, as permitted or assigned by the equipment owner.
	Electric Reliability Organization	ERO		An organization with Statutory Authority to regulate reliability
	External Routable Connectivity			The ability to access a BES Cyber System from a Cyber Asset that is outside of its associated Electronic Security Perimeter via a bi-directional routable protocol connection.

Railbelt Term	Acronym	Approved Date	Definition
Facility			A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.).
Facility Rating			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.
Fault			An event occurring on an electric system such as a short circuit, a broken wire, or an intermittent connection.
Fire Risk			The likelihood that a fire will ignite or spread in a particular geographic area.
Firm Demand			That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions.
Firm Transmission Service			The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.
Flashover			An electrical discharge through air around or over the surface of insulation, between objects of different potential, caused by placing a voltage across the air space that results in the ionization of the air space.
Flowgate			A designated point on the transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions.

	Railbelt Term	Acronym	Approved Date	Definition
	Flowgate			1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System.
	Flowgate Methodology			The Flowgate methodology is characterized by identification of key Facilities as Flowgates. Total Flowgate Capabilities are determined based on Facility Ratings and voltage and stability limits. The impacts of Existing Transmission Commitments (ETCs) are determined by simulation. The impacts of ETC, Capacity Benefit Margin (CBM) and Transmission Reliability Margin (TRM) are subtracted from the Total Flowgate Capability, and Postbacks and counterflows are added, to determine the Available Flowgate Capability (AFC) value for that Flowgate. AFCs can be used to determine Available Transfer Capability (ATC).
	Forced Outage			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.
R	Frequency Bias	**B**		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.

	Railbelt Term	Acronym	Approved Date	Definition
R	Frequency Bias Setting			A value, usually expressed in MW/0.1 Hz, set into a Balancing Authority ACE algorithm that allows the Balancing Authority to contribute its frequency response to the Interconnection. The algebraic sign of Frequency Bias is negative.
R	Frequency Bias Setting			A number, either fixed or variable, usually expressed in MW/0.1 Hz, included in a Balancing Authority's Area Control Error equation to account for the Balancing Authority's inverse Frequency Response contribution to the Interconnection, and discourage response withdrawal through secondary control systems. The algebraic sign of Frequency bias is negative.
	Frequency Deviation			A change in Interconnection frequency.
	Frequency Error			The difference between the actual and scheduled frequency. ($F_A - F_S$)
	Frequency Regulation			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.
R	Frequency Response	β		(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). The algebraic sign of frequency response is negative.

Railbelt Term	Acronym	Approved Date	Definition
Frequency Response Measure	FRM		The median of all the Frequency Response observations reported annually by Balancing Authorities or Frequency Response Sharing Groups for frequency events specified by the ERO (Electric Reliability Organization). This will be calculated as MW/0.1Hz.
Frequency Response Obligation	FRO		The Balancing Authority's share of the required Frequency Response needed for the reliable operation of an Interconnection. This will be calculated as MW/0.1Hz.
Frequency Response Sharing Group	FRSG		A group whose members consist of two or more Balancing Authorities that collectively maintain, allocate, and supply operating resources required to jointly meet the sum of the Frequency Response Obligations of its members.

	Railbelt Term	Acronym	Approved Date	Definition
R	Generator Operator	GOP		The entity that operates Generating Assets and performs the functions of supplying energy and Interconnected Operations Services.
R	Generator Owner	GO		Entity that owns and maintains Generating Assets.
	Generator Shift Factor	GSF		A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate.
	Generator-to-Load Distribution Factor	GLDF		The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate.
R	Generating Assets	GA		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.).
	Generation Capability Import Requirement	GCIR		The amount of generation capability from external sources identified by a Load-Serving Entity (LSE) or Resource Planner (RP) to meet its generation reliability or resource adequacy requirements as an alternative to internal resources.
	Good Utility Practice			From FERC Pro-Forma OATT-1.15 Good Utility Practice: Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or 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, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region, including those practices required by Federal Power Act section 215(a)(4).

Railbelt Term	Acronym	Approved Date	Definition
Host Balancing Authority			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.
Hourly Value			Data measured on a Clock Hour basis.

	Railbelt Term	Acronym	Approved Date	Definition
	Implemented Interchange			The state where the Balancing Authority enters the Confirmed Interchange into its Area Control Error equation.
	Inadvertent Interchange			The difference between the Balancing Authority's Net Actual Interchange and Net Scheduled Interchange. ($I_A - I_S$)
	Independent Power Producer	IPP		Any entity that owns or operates an electricity generating facility that is not included in an electric utility's rate base. This term includes, but is not limited to, cogenerators and small power producers and all other nonutility electricity producers, such as exempt wholesale generators, who sell electricity.
R	Independent System Operator	ISO		An Entity with characteristics and functions substantially similar to and RTO recognized but not necessarily authorized by the RCA. The entity either has not formally petitioned the RCA for status as an RTO, or does not fully meet the requirements of an RTO. Often developed around the framework of an existing power pool.
	Institute of Electrical and Electronics Engineers, Inc.	IEEE		

Railbelt Term	Acronym	Approved Date	Definition
Interactive Remote Access			User-initiated access by a person employing a remote access client or other remote access technology using a routable protocol. Remote access originates from a Cyber Asset that is not an Intermediate Device and not located within any of the Responsible Entity's Electronic Security Perimeter(s) or at a defined Electronic Access Point (EAP). Remote access may be initiated from: 1) Cyber Assets used or owned by the Responsible Entity, 2) Cyber Assets used or owned by employees, and 3) Cyber Assets used or owned by vendors, contractors, or consultants. Interactive remote access does not include system-to-system process communications.
Interchange			Energy transfers that cross Balancing Authority boundaries.
Interchange Authority	IA		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 purposes.
Interchange Distribution Calculator	IDC		A mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Interconnection.
Interchange Schedule			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.

Railbelt Term	Acronym	Approved Date	Definition
Interchange Transaction			An agreement to transfer energy from a seller to a buyer that crosses one or more Balancing Authority Area boundaries.
Interchange Transaction Tag or Tag			The details of an Interchange Transaction required for its physical implementation.
Interconnected Operations Service			A service (exclusive of basic energy and transmission services) that is required to support the reliable operation of interconnected Bulk Electric Systems.
Interconnection			When capitalized, any one of the three major electric system networks in North America: Eastern, Western, and ERCOT And the minor interconnections of Hawaii, Railbelt Alaska.
Interconnection Reliability Operating Limit	IROL		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.
Interconnection Reliability Operating Limit	IROL		A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading outages[3] that adversely impact the reliability of the Bulk Electric System.

[3] On September 13, 2012, FERC issued an Order approving NERC's request to modify the reference to "Cascading Outages" to "Cascading outages" within the definition of IROL due to the fact that the definition of "Cascading Outages" was previously remanded by FERC.

Railbelt Term	Acronym	Approved Date	Definition
Interconnection Reliability Operating Limit T_V	IROL T_V		The maximum time that an Interconnection Reliability Operating Limit can be violated before the risk to the interconnection or other Reliability Coordinator Area(s) becomes greater than acceptable. Each Interconnection Reliability Operating Limit's T_V shall be less than or equal to 30 minutes.
Interconnected Value			The technical value of a generating asset to the Railbelt Grid and it's 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.
Intermediate Balancing Authority			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.
Intermediate System			A Cyber Asset or collection of Cyber Assets performing access control to restrict Interactive Remote Access to only authorized users. The Intermediate System must not be located inside the Electronic Security Perimeter.
Interpersonal Communication			Any medium that allows two or more individuals to interact, consult, or exchange information.
Interruptible Load or Interruptible Demand			Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.

	Railbelt Term	Acronym	Approved Date	Definition
R	Largest Single Contingency	LSC		The largest single source (either transmission or generation) which can be removed from the area under study by a single system level event i.e. opening of a transmission line or breaker etc.
R	Largest Single Generation Contingency	LSGC		The Declared Capability of 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.
	Limiting Element			The element that is 1.) Either operating at its appropriate rating, or, 2.) Would be following the limiting contingency. Thus, the Limiting Element establishes a system limit.
	Load			An end-use device or customer that receives power from the electric system.
	Load Shift Factor	LSF		A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.
	Load-Serving Entity	LSE		Secures energy and transmission service (and related Interconnected Operations Services) to serve the electrical demand and energy requirements of its end-use customers.
	Long-Term Transmission Planning Horizon			Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

	Railbelt Term	Acronym	Approved Date	Definition
	Market Flow			The total amount of power flowing across a specified Facility or set of Facilities due to a market dispatch of generation internal to the market to serve load internal to the market.
	Minimum Vegetation Clearance Distance	MVCD		The calculated minimum distance stated in feet (meters) to prevent flash-over between conductors and vegetation, for various altitudes and operating voltages.
	Misoperation			• Any failure of a Protection System element to operate within the specified time when a fault or abnormal condition occurs within a zone of protection. • Any operation for a fault not within a zone of protection (other than operation as backup protection for a fault in an adjacent zone that is not cleared within a specified time for the protection for that zone). • Any unintentional Protection System operation when no fault or other abnormal condition has occurred unrelated to on-site maintenance and testing activity.

Railbelt Term	Acronym	Approved Date	Definition
Native Load			The end-use customers that the Load-Serving Entity is obligated to serve.
Near-Term Transmission Planning Horizon			The transmission planning period that covers Year One through five.
Net Actual Interchange			The algebraic sum of all metered interchange over all interconnections between two physically Adjacent Balancing Authority Areas.
Net Energy for Load			Net Balancing Authority Area generation, plus energy received from other Balancing Authority Areas, less energy delivered to Balancing Authority Areas through interchange. It includes Balancing Authority Area losses but excludes energy required for storage at energy storage facilities.
Net Interchange Schedule			The algebraic sum of all Interchange Schedules with each Adjacent Balancing Authority.
Net Scheduled Interchange			The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.
Network Integration Transmission Service			Service that allows an electric transmission customer to integrate, plan, economically dispatch and regulate its network reserves in a manner comparable to that in which the Transmission Owner serves Native Load customers.

Railbelt Term	Acronym	Approved Date	Definition
Non-Consequential Load Loss			Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load, or (3) Load that is disconnected from the System by end-user equipment.
Non-Firm Transmission Service			Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.
Non-Spinning Reserve			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 Clearing			A protection system operates as designed and the fault is cleared in the time normally expected with proper functioning of the installed protection systems.
Normal Rating			The rating as defined by the equipment owner that specifies the level of electrical loading, usually expressed in megawatts (MW) or other appropriate units that a system, facility, or element can support or withstand through the daily demand cycles without loss of equipment life.

Railbelt Term	Acronym	Approved Date	Definition
Obligated Entity			A Railbelt Entity who is obligated to provide operating and or non-operating reserves or reserve capacity under AKRES-001-0; usually but not always a Generation owner operator, a Load Serving Entity or its Balancing Authority.
Off-Peak			Those hours or other periods defined by North American Energy Standards Board (NAESB) business practices, contract, agreements, or guides as periods of lower electrical demand.
On-Peak			Those hours or other periods defined by NAESB business practices, contract, agreements, or guides as periods of higher electrical demand.
Open Access Same Time Information Service	OASIS		An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.
Open Access Transmission Tariff	OATT		Electronic transmission tariff accepted by the Regulatory Commission of Alaska (RCA) requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.
Operating Plan			A document that identifies a group of activities that may be used to achieve some goal. An Operating Plan may contain Operating Procedures and Operating Processes. A company-specific system restoration plan that includes an Operating Procedure for black-starting units, Operating Processes for communicating restoration progress with other entities, etc., is an example of an Operating Plan.

Railbelt Term	Acronym	Approved Date	Definition
Operating Procedure			A document that identifies specific steps or tasks that should be taken by one or more specific operating positions to achieve specific operating goal(s). The steps in an Operating Procedure should be followed in the order in which they are presented, and should be performed by the position(s) identified. A document that lists the specific steps for a system operator to take in removing a specific transmission line from service is an example of an Operating Procedure.
Operating Process			A document that identifies general steps for achieving a generic operating goal. An Operating Process includes steps with options that may be selected depending upon Real-time conditions. A guideline for controlling high voltage is an example of an Operating Process.
Operating Reserve			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			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; or • Load fully removable from the system within the Disturbance Recovery Period following the contingency event.
Operating Reserve –Supplemental			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 Disturbance Recovery Period following the contingency event.

Railbelt Term	Acronym	Approved Date	Definition
Operating Voltage			The voltage level by which an electrical system is designated and to which certain operating characteristics of the system are related; also, the effective (root-mean- square) potential difference between any two conductors or between a conductor and the ground. The actual voltage of the circuit may vary somewhat above or below this value.
Operational Planning Analysis			An analysis of the expected system conditions for the next day's operation. (That analysis may be performed either a day ahead or as much as 12 months ahead.) Expected system conditions include things such as load forecast(s), generation output levels, and known system constraints (transmission facility outages, generator outages, equipment limitations, etc.).
Outage Transfer Distribution Factor	OTDF		In the post-contingency configuration of a system under study, the electric Power Transfer Distribution Factor (PTDF) with one or more system Facilities removed from service (outaged).
Overlap Regulation Service			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.

Railbelt Term	Acronym	Approved Date	Definition
Participation Factors			A set of dispatch rules such that given a specific amount of load to serve, an approximate generation dispatch can be determined. To accomplish this, generators are assigned a percentage that they will contribute to serve load.
Peak Demand			1. The highest hourly integrated Net Energy For Load within a Balancing Authority Area occurring within a given period (e.g., day, month, season, or year). 2. The highest instantaneous demand within the Balancing Authority Area.
Performance-Reset Period			The time period that the entity being assessed must operate without any violations to reset the level of non-compliance to zero.
Physical Access Control Systems	PACS		Cyber Assets that control, alert, or log access to the Physical Security Perimeter(s), exclusive of locally mounted hardware or devices at the Physical Security Perimeter such as motion sensors, electronic lock control mechanisms, and badge readers.
Physical Security Perimeter	PSP		The physical, completely enclosed ("six-wall") border surrounding computer rooms, telecommunications rooms, operations centers, and other locations in which Critical Cyber Assets are housed and for which access is controlled.
Physical Security Perimeter	PSP		The physical border surrounding locations in which BES Cyber Assets, BES Cyber Systems, or Electronic Access Control or Monitoring Systems reside, and for which access is controlled.

Railbelt Term	Acronym	Approved Date	Definition
Planning Assessment			Documented evaluation of future Transmission system performance and Corrective Action Plans to remedy identified deficiencies.
Planning Authority	PA		The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.
Planning Coordinator	PC		See Planning Authority.
Point of Delivery	POD		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		A location that the Transmission Service Provider specifies on its transmission system where an Interchange Transaction enters or a Generator delivers its output.
Point to Point Transmission Service	PTP		The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery.
Postback			Positive adjustments to ATC or AFC as defined in Business Practices. Such Business Practices may include processing of redirects and unscheduled service.

Railbelt Term	Acronym	Approved Date	Definition
Power Transfer Distribution Factor	PTDF		In the pre-contingency configuration of a system under study, a measure of the responsiveness or change in electrical loadings on transmission system Facilities due to a change in electric power transfer from one area to another, expressed in percent (up to 100%) of the change in power transfer.
Pro Forma Tariff			Usually refers to the standard OATT and/or associated transmission rights mandated by the U.S. Federal Energy Regulatory Commission Order No. 888.
Protected Cyber Assets	PCA		One or more Cyber Assets connected using a routable protocol within or on an Electronic Security Perimeter that is not part of the highest impact BES Cyber System within the same Electronic Security Perimeter. The impact rating of Protected Cyber Assets is equal to the highest rated BES Cyber System in the same ESP. A Cyber Asset is not a Protected Cyber Asset if, for 30 consecutive calendar days or less, it is connected either to a Cyber Asset within the ESP or to the network within the ESP, and it is used for data transfer, vulnerability assessment, maintenance, or troubleshooting purposes.
Protection System			Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry.
Protection System			Protection System – • Protective relays which respond to electrical quantities, • Communications systems necessary for correct operation of protective functions • Voltage and current sensing devices providing inputs to protective relays, • Station dc supply associated with protective functions (including batteries, battery chargers, and non-battery- based dc supply), and • Control circuitry associated with protective functions through the trip coil(s) of the circuit breakers or other interrupting devices.

Railbelt Term	Acronym	Approved Date	Definition
Protection System Maintenance Program	PSMP		An ongoing program by which Protection System components are kept in working order and proper operation of malfunctioning components is restored. A maintenance program for a specific component includes one or more of the following activities: Verify — Determine that the component is functioning correctly. Monitor — Observe the routine in-service operation of the component. Test — Apply signals to a component to observe functional performance or output behavior, or to diagnose problems. Inspect — Examine for signs of component failure, reduced performance or degradation. Calibrate — Adjust the operating threshold or measurement accuracy of a measuring element to meet the intended performance requirement.
Pseudo-Tie			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		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 Term	Acronym	Approved Date	Definition
R	Railbelt (Railbelt Grid, Railbelt Interconnect			The *interconnected* generation and transmission system of the Central Alaska, currently The Railbelt Region extending from North of the Fairbanks area to the Katchemak bay area in the South.
R	Railbelt Entity			Any entity owning, operating or maintaining any electrical facilities which separately or in aggregate are capable of measurably and meaningfully influencing the Railbelt Grid's frequency or voltage profile. This term is to be interpreted in the broadest sense in the context of preserving Railbelt Grid Reliability.
	Ramp Rate or Ramp			(Schedule) The rate, expressed in megawatts per minute, at which the interchange schedule is attained during the ramp period. (Generator) The rate, expressed in megawatts per minute, that a generator changes its output.
	Rated Electrical Operating Conditions			The specified or reasonably anticipated conditions under which the electrical system or an individual electrical circuit is intend/designed to operate.
	Rating			The operational limits of a transmission system element under a set of specified conditions.
	Rated System Path Methodology			The Rated System Path Methodology is characterized by an initial Total Transfer Capability (TTC), determined via simulation. Capacity Benefit Margin, Transmission Reliability Margin, and Existing Transmission Commitments are subtracted from TTC, and Postbacks and counterflows are added as applicable, to derive Available Transfer Capability. Under the Rated System Path Methodology, TTC results are generally reported as specific transmission path capabilities.

Railbelt Term	Acronym	Approved Date	Definition
Reactive Power	VARS		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 equipment such as capacitors and directly influences electric system voltage. It is usually expressed in kilovars (kvar) or megavars (Mvar).
Real Power	WATTS		The portion of electricity that supplies energy to the load.
Reallocation			The total or partial curtailment of Transactions during TLR to allow Transactions using higher priority to be implemented.
Real-time			Present time as opposed to future time. (From Interconnection Reliability Operating Limits standard).
Real-time Assessment			An examination of existing and expected system conditions, conducted by collecting and reviewing immediately available data.
Receiving Balancing Authority			The Balancing Authority importing the Interchange.
Regional Reliability Organization	RRO		1. An entity that ensures that a defined area of the Bulk Electric System is reliable, adequate and secure. 2. A RCA recognized or authorized Regional Reliability Organization can serve as the Compliance Monitor.

	Railbelt Term	Acronym	Approved Date	Definition
	Regional Reliability Plan			The plan that specifies the Reliability Coordinators and Balancing Authorities within the Regional Reliability Organization, and explains how reliability coordination will be accomplished.
R	Regional Transmission Organization	RTO		An organization formed with the approval of the RCA to coordinate, control and monitor operation of the Electric Power System within a given region of the State. Characteristics: 1. Independence from market participants; 2. Appropriate scope and regional configuration; 3. Possession of operational authority for all transmission facilities under the RTO's control; and 4. Exclusive authority to maintain short-term reliability. Functions: 1. Administer its own tariff and employ a transmission pricing system that will integrate reliability costs into transmission pricing, promote efficient use and expansion of transmission and generation facilities; 2. Create market mechanisms to manage transmission congestion; 3. Develop and implement procedures to address parallel path flow issues; 4. Serve as a supplier of last resort for all ancillary services (Similar to the requirements in FERC Order No. 888 and subsequent FERC orders); 5. Operate a single OASIS site for all transmission facilities under its control with responsibility for independently calculating TTC and ATC; 6. Monitor markets to identify design flaws and market power; and 7. Plan and coordinate necessary transmission additions and upgrades; 8. Perform region wide security constrained economic dispatch of real and reactive resources, often dispatched through existing Load Balancing Authorities.
R	Regulating Reserve			An amount of reserve responsive to Automatic Generation Control, which is sufficient to provide normal regulating margin; above and beyond the spinning reserve requirement.

	Railbelt Term	Acronym	Approved Date	Definition
	Regulation Service			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 NERC for itself and the Balancing Authority for which it is providing the Regulation Service.
	Reliability Adjustment RFI			Request to modify an Implemented Interchange Schedule for reliability purposes.
	Reliability Coordinator	RC		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			The collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

	Railbelt Term	Acronym	Approved Date	Definition
	Reliability Coordinator Information System	RCIS		The system that Reliability Coordinators use to post messages and share operating information in real time.
	Reliability Directive			A communication initiated by a Reliability Coordinator, Transmission Operator, or Balancing Authority where action by the recipient is necessary to address an Emergency or Adverse Reliability Impact.
	Remedial Action Scheme	RAS		See "Special Protection System".
	Reportable Cyber Security Incident			A Cyber Security Incident that has compromised or disrupted one or more reliability tasks of a functional entity.
R	Reliability Standard			A standard similar in function to those required by the United States Federal Energy Regulatory Commission under Section 215 of the Federal Power Act, adopted by a regional utility body and approved or recognized by an applicable authority in jurisdiction not regulated by FERC. Reliability standards provide for "Reliable Operation" of the bulk-power system "Bulk-Power System". The term includes requirements for the operation of existing bulk-power system facilities, including cyber-security protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation Reliable Operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity.
	Reliable Operation			Operating the elements of the bulk-power system "Bulk- Power System" within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cyber-security incident, or unanticipated failure of system elements.

	Railbelt Term	Acronym	Approved Date	Definition
R	Reportable Disturbance			Any event that causes an ACE change greater than or equal to 80% of a Balancing Authority's or reserve sharing group's most severe contingency, or 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.
	Request for Interchange	RFI		A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.
	Reserve Sharing Group	RSG		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 Disturbance Control Performance, the Areas become a Reserve Sharing Group.
	Resource Planner	RP		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.

Railbelt Term	Acronym	Approved Date	Definition
Response Rate			The Ramp Rate that a generating unit can achieve under normal operating conditions expressed in megawatts per minute (MW/Min).
Right-of-Way	ROW		A corridor of land on which electric lines may be located. The Transmission Owner may own the land in fee, own an easement, or have certain franchise, prescription, or license rights to construct and maintain lines.
Right-of-Way	ROW		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.
Right-of-Way	ROW		The corridor of land under a transmission line(s) needed to operate the line(s). The width of the corridor is established by engineering or construction standards as documented in either construction documents, pre-2007 vegetation maintenance records, or by the blowout standard in effect when the line was built. The ROW width in no case exceeds the Transmission Owner's legal rights but may be less based on the aforementioned criteria.

	Railbelt Term	Acronym	Approved Date	Definition
	Scenario			Possible event.
	Schedule			(Verb) To set up a plan or arrangement for an Interchange Transaction. (Noun) An Interchange Schedule.
	Scheduled Frequency			60.0 Hertz, except during a time correction.
	Scheduling Entity			An entity responsible for approving and implementing Interchange Schedules.
	Scheduling Path			The Transmission Service arrangements reserved by the Purchasing-Selling Entity for a Transaction.
	Sending Balancing Authority			The Balancing Authority exporting the Interchange.
R	Share			The proportionate share of a Joint Owned Generating Unit (or combination of units with a single point of interconnection regardless of RAS applications) belonging to a single entity.
	Sink Balancing Authority			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			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).

	Railbelt Term	Acronym	Approved Date	Definition
	Special Protection System (Remedial Action Scheme)	SPS		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.
	Spinning Reserve			Unloaded generation that is synchronized and ready to serve additional demand.
R	Spinning Reserve Largest Contingency Ratio	SRLCR		The ratio of an individual Entities' Largest Generating Contingency to the sum of the Largest Generating Contingencies of all the Railbelt entities.
	Stability			The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances.
	Stability Limit			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.
	Supervisory Control and Data Acquisition	SCADA		A system of remote control and telemetry used to monitor and control the transmission system.
	Supplemental Regulation Service			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.

Railbelt Term	Acronym	Approved Date	Definition
Surge			A transient variation of current, voltage, or power flow in an electric circuit or across an electric system.
Sustained Outage			The de-energized condition of a transmission line resulting from a fault or disturbance following an unsuccessful automatic reclosing sequence and/or unsuccessful manual reclosing procedure.
System			A combination of generation, transmission, and distribution components.
System Operating Limit	SOL		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			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		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 Contingency.

Railbelt Term	Acronym	Approved Date	Definition
Telemetering			The process by which measurable electrical quantities from substations and generating stations are instantaneously transmitted to the control center, and by which operating commands from the control center are transmitted to the substations and generating stations.
Thermal Rating			The maximum amount of electrical current that a transmission line or electrical facility can conduct over a specified time period before it sustains permanent damage by overheating or before it sags to the point that it violates public safety requirements.
Tie Line			A circuit connecting two Balancing Authority Areas.
Tie Line Bias			A mode of Automatic Generation Control that allows the Balancing Authority to 1.) Maintain its Interchange Schedule and 2.) Respond to Interconnection frequency error.
Time Error			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			An offset to the Interconnection's scheduled frequency to return the Interconnection's Time Error to a predetermined value.

	Railbelt Term	Acronym	Approved Date	Definition
R	TLR Log			Report required to be filed after every Transmission Load Reduction Level 2 or higher in a specified format. Initiating Balancing Authority prepares the report. The report is electronically filed on the IOC reliability web site.
	Total Flowgate Capability	TFC		The maximum flow capability on a Flowgate, is not to exceed its thermal rating, or in the case of a flowgate used to represent a specific operating constraint (such as a voltage or stability limit), is not to exceed the associated System Operating Limit.
T	Total Operating Reserve	TOR		The Total Operating Reserve for the Railbelt is 150% of the largest generating unit contingency in operation on the Railbelt Interconnection. (further described in agreement entitled "Addendum H" of the separate amended and restated "Alaska Intertie Agreement").
	Total Transfer Capability	TTC		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.
	Transaction			See Interchange Transaction.
	Transfer Capability			The measure of the ability of interconnected electric systems to move or transfer power *in a reliable manner* from one area to another over all transmission lines (or paths) between those areas under specified system conditions. The units of transfer capability are in terms of electric power, generally expressed in megawatts (MW). The transfer capability from "Area A" to "Area B" is *not g*enerally equal to the transfer capability from "Area B" to "Area A".

	Railbelt Term	Acronym	Approved Date	Definition
	Transfer Distribution Factor			See Distribution Factor.
R	Transmission			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 69kV.
	Transmission Constraint			A limitation on one or more transmission elements that may be reached during normal or contingency system operations.
	Transmission Customer			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.
R	Transmission Line			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.
	Transmission Operator	TOP		The entity responsible for the reliability of its "local" transmission system, and that operates or directs the operations of the transmission facilities.

Railbelt Term	Acronym	Approved Date	Definition
Transmission Operator Area			The collection of Transmission assets over which the Transmission Operator is responsible for operating.
Transmission Owner	TO		The entity that owns and maintains transmission facilities.
Transmission Planner	TP		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		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 Reliability Margin Implementation Document	TRMID		A document that describes the implementation of a Transmission Reliability Margin methodology, and provides information related to a Transmission Operator's calculation of TRM.
Transmission Service			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		The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements.

Railbelt Term	Acronym	Approved Date	Definition
Vegetation			All plant material, growing or not, living or dead.
Vegetation Inspection			The systematic examination of a transmission corridor to document vegetation conditions.
Vegetation Inspection			The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the Transmission Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Vegetation Inspection			The systematic examination of vegetation conditions on a Right-of-Way and those vegetation conditions under the applicable Transmission Owner's or applicable Generator Owner's control that are likely to pose a hazard to the line(s) prior to the next planned maintenance or inspection. This may be combined with a general line inspection.
Wide Area			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 Interconnected Reliability Operating Limits.
Year One			The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For an assessment started in a given calendar year, Year One includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One includes the forecasted peak Load period for either 2012 or 2013.

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 (B)	Higher of $1000 or $10 per MW of Sanction Measure	Higher of $2000 or $20 per MW of Sanction Measure
Level 2	Letter (B)	Higher of $1000 or $10 per MW of Sanction Measure	Higher of $2000 or $20 per MW of Sanction Measure	Higher of $4000 or $40 per MW of Sanction Measure
Level 3	Higher of $1000 or $10 per MW of Sanction Measure	Higher of $2000 or $20 per MW of Sanction Measure	Higher of $4000 or $40 per MW of Sanction Measure	Higher of $6000 or $60 per MW of Sanction Measure
Level 4	Higher of $2000 or $20 per MW of Sanction Measure	Higher of $4000 or $40 per MW of Sanction Measure	Higher of $6000 or $60 per MW of Sanction Measure	Higher of $10,000 or $100 per MW of Sanction Measure

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	AMLP	CEA	CEA	GVEA	GVEA		
	Load Serving Entity		Chugach	AML&P	HEA	MEA	GVEA	GVEA ROC+Hz**	% of MW Value	Comment
Load Sed 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 III	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					AMLP 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 thatn 15 MW.

ALASKA SYSTEMS COORDINATING COUNCIL

An association of Alaska's electric power systems promoting improved reliability through systems coordination

ASCC OPERATING GUIDES FOR INTERCONNECTED UTILITIES

and Alaska Intertie Operating Guides

February 1992

ALASKA SYSTEMS COORDINATING COUNCIL

An association of Alaska's electric power systems promoting improved reliability through systems coordination

ASCC PLANNING CRITERIA

for the reliability of interconnected electric utilities

May 1991

Letter from Intertie Management Committee
to Regulatory Commission of Alaska
Dated January 27, 2014
Subject: The Alaska Intertie – Railbelt
Operating and Reliability Standards

Exhibit 2

Amended and Restated
Alaska Intertie Agreement
dated November 18, 2011
included Exhibits A-H to
Amended and Restated
Alaska Intertie Agreement
dated November 18, 2011

AMENDED AND RESTATED

ALASKA INTERTIE AGREEMENT

Among

ALASKA ENERGY AUTHORITY;
MUNICIPALITY OF ANCHORAGE, ALASKA
d.b.a. MUNICIPAL LIGHT AND POWER;
CHUGACH ELECTRIC ASSOCIATION, INC.;
GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.;
ALASKA ELECTRIC GENERATION and
TRANSMISSION COOPERATIVE, INC.

November 18, 2011

TABLE OF CONTENTS

Table of Contents....1-8

Incorporated Exhibits List....9

Recitals....10

Article 1. Definitions.... 12

Article 2. Term and Effective Date.... 12

Section 2.1 Effective Date.... 12

Section 2.2 Termination.... 12

2.2.1 Mutual Consent.... 12

2.2.2 Participant and AEA.... 12

2.2.3 AEA Financial Obligations.... 12

2.2.4 Limitation for Financing.... 12

Article 3. Operating and Reliability Standards and Enforcement.... 13

Section 3.1 Adoption of Operating Policies and Procedures, and Reliability Standards.... 13

3.1.1 AEA Responsibilities.... 13

3.1.2 Notice Required.... 13

Section 3.2 Compliance with Standards.... 13

Section 3.3 Implementation – Participants and Users.... 14

Section 3.4 Replacement of Reliability Standards.... 14

Section 3.5 Operating Committee.... 14

Section 3.6 Required Data Submissions.... 14

Section 3.7 AEA Power Project Compliance.... 14

Article 4. Participant.... 15

Section 4.1 Participant Defined.... 15

Section 4.2 New Participant.... 15

Section 4.3 Membership in IMC.... 15

Article 5. Withdrawal of AEG&T and Other Participant and User Status.... 15

Section 5.1 Withdrawal of AEG&T.... 15

Section 5.2 Substitution of HEA and MEA, and Admission of City of Seward and the United States Army.... 16

Article 6. Minimum Rights of the Participants and Users to Use Intertie Facilities.... 16

Section 6.1 Minimum Intertie Transfer Capability Rights ("MITCR").... 16

6.1.1 Right of First Refusal. 16
6.1.2 Allocation of Transfer Capability 16
6.1.3 Emergency Operations. 16
Section 6.2 Determination of MITCR 17
6.2.1 Methodology. 17
6.2.2 Unused MITCR. 17
6.2.3 Right to Contractually Transfer MITCR. 17
6.2.4 IMC Authority to Change Capacity Allocation Methodology. 18
6.2.5 New State Power Projects. 18
Section 6.3 Maximum Intertie Transfer Capability 18
Section 6.4 Improvements to the Intertie 19
6.4.1 Development of Improvements. 19
6.4.2 Requests for Improvements. 19
6.4.3 Responsibility for Cost of Improvements. 20
6.4.4 Right to Make Improvements – Required Work. 20
6.4.5 Notice. 20
Section 6.5 Additional Project Taps 20
Article 7. Costs for Intertie Transfer Rights 21
Section 7.1 Intertie Costs 21
7.1.1 Costs to Be Shared by Participants and Users. 21
7.1.2 Annual Budget and Fiscal Year 22
Section 7.2 Calculation of Intertie Costs and Rates 22
7.2.1 Participant and User Estimates, Participant Historical Data. 22
7.2.2 IMC Estimates. 22
7.2.3 Comments. 23
7.2.4 IMC Determination of Estimated Intertie Usage. 23
7.2.5 Energy Rate. 23
7.2.6 Capacity Rate. 23
Section 7.3 Allocation of Intertie Costs 23
7.3.1 Participant and User Payments. 23
7.3.2 Annual Payment of Intertie Costs. 24

7.3.3 Monthly Use. 24
7.3.4 Excess Revenues. 24
7.3.5 Revenue Deficiencies. 24
Article 8. Intertie Management Committee 24
Section 8.1 Establishment of the Intertie Management Committee, Right to Vote 24
8.1.1 Eligibility to Vote. 25
8.1.2 Minutes. 25
Section 8.2 Adoption of Procedural Rules or Bylaws 25
Section 8.3 Effect of Abstention. 25
Section 8.4 Meetings by Electronic Communication. 25
Section 8.5 IMC Responsibilities 25
8.5.1 IMC Responsibilities and AEA Duties. 25
8.5.2 IMC Approvals. 26
Section 8.6 IMC Actions 26
8.6.1 Intertie Operation. 26
8.6.2 Intertie User Agreements 26
8.6.3 Non-Compliance Appeals. 26
8.6.4 O&M and Scheduling. 27
8.6.5 Budget. 27
8.6.6 Cost Allocation and Payment Schedule. 27
8.6.7 Maximum Capability and Capacity Allocation. 27
8.6.8 Determination of Actual Payment Obligation. 27
8.6.9 Funding Methods. 28
8.6.10 Improvements. 28
8.6.11 Maintenance. 28
8.6.12 Creation of Reserve Fund. 28
8.6.13 Procurement of Services. 28
8.6.14 Miscellaneous. 28
Section 8.7 Payment Obligation Unimpaired 28
Section 8.8 AEA's Ability to Perform Required Work 28
Section 8.9 Payment Obligation and Rights of Review 29

Section 8.10 AEA Authority to Collect Payments and Disburse Funds 29
Article 9. Operating Committee 29
Section 9.1 Establishment of the Operating Committee 29
9.1.1 Establishment. 29
9.1.2 Representatives. 29
Section 9.2 Meetings of the Operating Committee 30
9.2.1 Meetings. 30
9.2.2 Voting. 30
9.2.3 Minutes. 30
9.2.4 Expenses. 30
9.2.5 Meetings by Electronic Communication. 30
Section 9.3 Operating Procedures 30
Article 10. Operation of the Intertie 31
Section 10.1 Responsibility for Operation of the Intertie 31
10.1.1 Responsible Participants. 31
10.1.2 AML&P and MEA Responsibilities. 31
10.1.3 GVEA Responsibilities. 31
10.1.4 Joint Responsibilities. 32
10.1.5 Contracting. 33
10.1.6 Load Balancing. 33
Section 10.2 Suspension of Work in Performance of Operational Duties 33
Section 10.3 Budget for Operation of the Intertie 33
10.3.1 Budget Process. 33
10.3.2 Participant Comments. 33
10.3.3 IMC Establishes Budget. 34
10.3.4 IMC Determinations and Payment of AML&P and GVEA. 34
10.3.5 Payment if IMC Unable to Determine Fixed Cost Fee. 34
Section 10.4 Accounting and Records 34
Section 10.5 Audits 34
10.5.1 Request for Audit. 34
10.5.2 State Audit. 35

Section 10.6 Payment of Operators 35
Section 10.7 Change in Ownership or Control 35
Section 10.8 Critical Repairs and Maintenance 35
Article 11. Scheduling of Capacity and Energy on the Intertie 35
Section 11.1 Scheduling Responsibility 35
11.1.1 Southern Group. 35
11.1.2 Northern Group. 36
11.1.3 Coordination. 36
Section 11.2 Capacity and Energy Schedules 36
11.2.1 Participant Hourly Schedules. 36
11.2.2 Advanced Scheduling. 36
11.2.3 Procedure. 36
11.2.4 Short-term Scheduling. 36
11.2.5 Modification of Scheduling Procedures. 36
Section 11.3 Intertie Schedule Limitations 36
Section 11.4 Transmission Service to Access the Intertie 37
Article 12. Maintenance of the Intertie Facilities 37
Section 12.1 Maintenance Responsibility 37
12.1.1 Responsibility for Maintenance Practices. 37
12.1.2 Availability. 37
Section 12.2 Maintenance Budget and Costs 37
12.2.1 Development of Budget. 37
12.2.2 Cost Records. 37
Article 13. Measurement of Electric Power and Energy 38
Section 13.1 Required Metering Facilities 38
Section 13.2 Access to Metering Facilities and Data 38
Section 13.3 Installation and Maintenance 38
Article 14. Transmission Losses 38
Section 14.1 Intertie Transmission and Transmission Service Losses 38
14.1.1 Method of Determination of Losses. 38
14.1.2 Compensation for Losses. 39

14.1.3 Schedules. 39
Section 14.2 Intertie Transmission Loss Compensation 39
Article 15. Rights of Users 39
Article 16. Open Access Principles 39
Section 16.1 Definition 39
Section 16.2 Purpose 39
Section 16.3 Implementation of Capacity Allocation Methodology 40
16.3.1 New Methodology. 40
16.3.2 Statutory Conditions. 40
16.3.3 Priority for AEA Contracts 40
16.3.4 Alternative Allocation of Intertie Capacity. 40
16.3.5 Federal Acquisition Regulations. 41
Section 16.4 Public Process 41
Section 16.5 Availability of Information 41
Section 16.6 Review of Methodology 41
Article 17. Billing and Payments 42
Section 17.1 Billing 42
Section 17.2 Billing Disputes 42
Section 17.3 Payment of Sanctions 42
Article 18. Insurance and Liability 42
Section 18.1 Insurance 42
Section 18.2 Types of Insurance 43
18.2.1 Workers' Compensation Insurance. 43
18.2.2 Comprehensive General Liability Insurance. 43
Section 18.3 Other Insurance Coverage Requirements 43
18.3.1 Participants' Cost Responsibility. 43
18.3.2 Users' Insurance Requirements. 43
18.3.3 Coverage and Certificates. 43
Article 19. Review of Decision 44
Section 19.1 Review of IMC Decision 44
Section 19.2 Initiation of Review 44

Section 19.3 Review Process 44
19.3.1 Settlement Conference. 44
19.3.2 Disposition of Dispute. 44
Article 20. Indemnity 45
Section 20.1 Responsibility; Cost of Indemnity 45
20.1.1 Costs of Indemnity. 45
20.1.2 Participant Indemnity. 45
20.1.3 IMC Indemnity. 45
20.1.4 User Agreements. 45
Section 20.2 Comparative Negligence 45
Article 21. Warranty Denial and Exclusivity of Contract 46
Section 21.1 AEA Denial of Warranty 46
Section 21.2 Exclusivity of Contract 46
Article 22. Uncontrollable Forces 46
Section 22.1 Limited Excuse of Performance. 46
Section 22.2 Suspension of Performance. 46
Article 23. Waivers 46
Article 24. Successors and Assigns; No Third Party Beneficiaries 47
Section 24.1 Successors and Assigns 47
Section 24.2 No Third-Party Beneficiaries 47
Article 25. Governing Law 47
Article 26. Captions, Merger of Addenda and Exhibits 47
Section 26.1 Captions 47
Section 26.2 Merger 47
Article 27. Notices 48
Section 27.1 Notices 48
27.1.1 Address. 48
27.1.2 Means of Notice. 49
Article 28. Amendments 49
Article 29. Mutual Right of Entry 49
Article 30. Agents 49

Article 31. Agreement Approval and Transmittal 50
Article 32. Construction of Agreement 51

Exhibit A – Former AS 44.83.380

Exhibit B – Definitions

Exhibit C – Form of New Participant Addendum

Exhibit D – Former AS 44.83.398(f)

Exhibit E – Intertie Facilities Diagram

Exhibit F – Form of User Agreement

Exhibit G - Sample MITCR Calculation

Exhibit H – Reserve Capacity and Operating Reserve Responsibility Agreement

Incorporated Exhibits

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AMENDED AND RESTATED

ALASKA INTERTIE AGREEMENT

Among

**ALASKA ENERGY AUTHORITY;
MUNICIPALITY OF ANCHORAGE, ALASKA
d.b.a. MUNICIPAL LIGHT AND POWER;
CHUGACH ELECTRIC ASSOCIATION, INC.;
GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.;
ALASKA ELECTRIC GENERATION and
TRANSMISSION COOPERATIVE, INC.**

This agreement ("Agreement"), is made and entered into this 18th day of November, 2011 ("Effective Date"), between ALASKA ENERGY AUTHORITY, a public corporation of the State of Alaska ("AEA"); MUNICIPAL LIGHT AND POWER, a department of THE MUNICIPALITY OF ANCHORAGE, ALASKA, ("AML&P"); CHUGACH ELECTRIC ASSOCIATION, INC., a not-for-profit electric cooperative membership corporation of the State of Alaska ("CEA"); GOLDEN VALLEY ELECTRIC ASSOCIATION, INC., a not-for-profit electric cooperative membership corporation of the State of Alaska ("GVEA"); ALASKA ELECTRIC GENERATION and TRANSMISSION COOPERATIVE, INC., a not-for-profit electric cooperative membership corporation of the State of Alaska ("AEG&T"). These entities, other than AEA, and subsequent qualifying signatories to this Agreement shall be referred to individually as "Participant" or collectively as "Participants."

WITNESSETH

WHEREAS, AML&P, CEA, GVEA, and AEG&T each own and operate electric utility facilities and/or are engaged in the business of providing Capacity and Energy to customers; and

WHEREAS, it is expected that entities other than the Participants will also use the Intertie; and

WHEREAS, the State of Alaska funded and AEA constructed the Intertie and made these electrical transmission facilities available to the Utility Participants under the Original Agreement for Capacity and Energy transactions to benefit Railbelt customers, ensure delivery of energy from State-owned projects, and improve reliability and economical Capacity and Energy deliveries to the Utility Participants' customers under the former Alaska Energy Program established by former AS 44.83.380 (attached as Exhibit A); and

WHEREAS, the Participants entered into the Original Agreement to improve the reliability of their interconnected electrical systems and engage in transactions for electrical Capacity and Energy with each other under individual contractual arrangements between the Participants using the Intertie; and

WHEREAS, the Intertie interconnected the Railbelt electric utility systems so that they operate in electrical synchronism; and

WHEREAS, AEA and the Participants desire to establish the Intertie Management Committee ("IMC") and provide it with primary responsibility for the governance, control, operation, maintenance, repair, and improvement of the Intertie; and

WHEREAS, AEA and the Participants desire to set forth the responsibilities and rights of all users of the Intertie ("Users"); and

WHEREAS, it is desirable to maintain the reliable operation of the Alaska Intertie for all Users; and

WHEREAS, it is desirable to have uniformly applicable standards for maintaining and enforcing reliability on the Intertie; and

WHEREAS, the Utility Participant Parties to the Original Agreement are also Parties to the Reserve Capacity and Operating Reserve Responsibility Agreement, a separate and independent contract that was made Addendum No. 1 to the Original Agreement in order to provide for the reliable operation of the Intertie and the interconnected Railbelt electrical system; and

WHEREAS, it is desirable for all Users to execute an Intertie User Agreement ("User Agreement") under the same terms and conditions and to be subject to the same operating policies and procedures, Reliability Standards, and compliance measures in keeping with Open Access principles; and

WHEREAS, the IMC is the appropriate organization to transition Intertie operations and policies to Open Access principles; and

WHEREAS, the management of the Intertie will be most effective if the IMC membership is made up of representatives of AEA and electric utilities who are qualifying Participants; and

WHEREAS, AEG&T shall be allowed to terminate its Participant status immediately upon its execution of this Agreement; and

WHEREAS, the members of AEG&T, Homer Electric Association, Inc. a not-for-profit electric cooperative membership corporation of the State of Alaska ("HEA") and, Matanuska Electric Association, Inc. a not-for-profit electric cooperative membership corporation of the State of Alaska ("MEA") individually shall have the one-time opportunity to become Participants immediately upon their timely execution of a New Participant Addendum; and

WHEREAS, the United States Army and the City of Seward individually shall be allowed to become a Participant immediately upon their timely execution of a New Participant Addendum;

THEREFORE, in consideration of the mutual covenants in this Agreement, AEA and the Participants agree as follows:

Article 1.
DEFINITIONS

Definitions are as specified in Exhibit B, attached hereto and incorporated herein by this reference. Exhibit B shall remain in effect during the term of this Agreement, but may be amended from time to time in the manner provided in Article 27, AMENDMENTS.

Article 2.
TERM AND EFFECTIVE DATE

Section 2.1 Effective Date

This Agreement supersedes the Original Agreement, and shall become effective immediately upon its execution by AEA and the Participants. This Agreement shall remain in full force and effect unless otherwise terminated as provided herein.

Section 2.2 Termination

2.2.1 Mutual Consent. This Agreement may be terminated at any time by the mutual consent of all Participants.

2.2.2 Participant and AEA. Any Participant may terminate its participation in this Agreement by giving at least thirty-six (36) months advanced written notice and paying or settling all of its outstanding obligations for Intertie Costs existing before the effective date of its termination, and including any other obligations related to Intertie financing or other funding or sanctions for non-compliance with Reliability Standards. AEA may terminate this Agreement by giving at least thirty-six (36) months advance written notice, and, if applicable, paying any amounts it is obligated to pay that were due and owing before the effective date of its termination. Termination of this Agreement is conditional upon AEA making a determination that such action is required to improve power systems serving utilities in the Railbelt. Unless it is otherwise agreed in writing, any Participant that terminates its participation shall be liable only for those Intertie Costs and other obligations that existed before the effective date of its termination, as set out above.

2.2.3 AEA Financial Obligations. In the event AEA incurs, or intends to incur, financial obligations that are recoverable from the Participants pursuant to Article 7, COSTS FOR INTERTIE TRANSFER RIGHTS, the Participants' requirement to provide advanced written notice of termination shall be thirty (30) calendar days. Termination under this Section shall not be effective until the terminating Participant has satisfied the requirements of Section 2.2.2, Participant and AEA.

2.2.4 Limitation for Financing. The Participants and AEA may agree to limit their respective rights under Sections 2.2.1, 2.2.2, and 2.2.3 to terminate this

Agreement in conjunction with bond or debt financing for repairs or improvements to the Intertie. To be effective, any such limitation agreed to pursuant to this Section 2.2.4 shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

Article 3.
OPERATING AND RELIABILITY STANDARDS AND ENFORCEMENT

Section 3.1 Adoption of Operating Policies and Procedures, and Reliability Standards

The IMC shall determine the operating policies and procedures for handling the obligations and responsibilities for providing Reserve Capacity and Operating Reserves for the Intertie. The IMC shall have the authority to adopt and implement operating policies and procedures, Reliability Standards for the Intertie, and enforcement processes, including sanctions and other remedies. All Participants and Users shall be obligated to comply with all operating policies and procedures and Reliability Standards adopted by the IMC. All operating policies and procedures and Reliability Standards shall be adopted, applied and enforced by the IMC in a uniform, non-preferential, just and reasonable manner that is not unjustly discriminatory. The adoption, amendment, or modification of operating policies and procedures shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC. The adoption, amendment, or modification of Reliability Standards and enforcement processes, including sanctions and other remedies shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

3.1.1 AEA Responsibilities. AEA shall have the authority to void any operating policies and procedures or Reliability Standards that AEA reasonably believes would adversely affect the safe operation of the Intertie, breach AEA's statutory mandates, or directly jeopardize AEA-owned Intertie assets in a manner that would be inconsistent with Prudent Utility Practices.

3.1.2 Notice Required. Except in the case of an emergency, AEA shall provide the IMC at least ten (10) business days prior written notice of its decision to void any operating policy and procedure or Reliability Standard.

Section 3.2 Compliance with Standards

In the event a User fails to comply with the Intertie operating policies and procedures or Reliability Standards, the User may be subject to any sanctions or other enforcement policies adopted by the IMC applicable to such non-compliance. Compliance with Intertie operating policies and procedures and Reliability Standards is a material obligation of this Agreement and the User Agreement.

Section 3.3 Implementation – Participants and Users

All Users shall execute any necessary agreements and take such reasonable actions as may be requested by the IMC in order to implement operating policies and procedures or Reliability Standards and any sanctions for non-compliance approved by the IMC. Each Participant or User shall require or be responsible for all non-residential customers or generation projects on the Participant's or User's system to comply with all applicable operating policies and procedures or Reliability Standards approved by the IMC as a condition of connection to the Participant's or User's system. The IMC, excluding AEA, shall assist in the enforcement of this provision.

Section 3.4 Replacement of Reliability Standards

In the event Reliability Standards adopted by the IMC are replaced or superseded in whole or in part by the order of a state or federal regulatory agency or by the terms of a state or federal regulation or statute, the IMC shall make amendments to or terminate the Reliability Standards to the extent the IMC deems prudent or necessary upon such change in accordance with Section 3.1, Adoption of Operating Policies and Procedures, and Reliability Standards.

Section 3.5 Operating Committee

The Operating Committee, established under Article 9, OPERATING COMMITTEE, shall advise the IMC on setting operating policies and procedures for the Intertie. The members of the Operating Committee shall have experience and expertise in the operation of electric utility transmission and distribution systems and the Railbelt's transmission system. The IMC shall give consideration to the group's proposals and take action to adopt, modify or reject any such proposal within one-hundred-twenty (120) calendar days.

Section 3.6 Required Data Submissions.

Each Participant and User (or their designated agent or Designated Contractor) shall submit to the IMC all data as reasonably requested by the IMC, whether related to any operating policies and procedures, Reliability Standards, or otherwise. A Participant or User shall notify the IMC of its designation of an agent or Designated Contractor prior to having that agent submit any data on behalf of the Participant or User.

Section 3.7 AEA Power Project Compliance

AEA anticipates that Users engaging in Intertie Transactions for transporting power from state projects (such as AEA's Bradley Lake Hydroelectric Project or future state-owned projects) will contractually assume responsibility for compliance with all applicable Intertie operating policies and procedures or Reliability Standards, and accept responsibility for any sanctions or other duties required of such Users by any operating policies and procedures or Reliability Standards. If Users transporting power from state projects assume those responsibilities, AEA or the state agency owning a power project shall not be directly or indirectly responsible for such compliance or sanctions absent their written agreement to assume such responsibility.

Article 4.
PARTICIPANT

Section 4.1 Participant Defined

Participants will be responsible for the governance of the Intertie through participation in the IMC in accordance with Section 4.3 Membership In IMC. For purposes of this Agreement, a Participant is: an electric public utility with at least an Annual System Demand of 5MW of retail load, holding a Certificate of Public Convenience and Necessity from the Regulatory Commission of Alaska, or having other equivalent authority; and, having a certificated service territory, or other equivalent authority, with physical or contractual access to the Alaska Intertie for the transport of electric power. A Participant must also meet all of the requirements of and agree to comply with the terms of this Agreement. Participants shall execute a User Agreement to have the right to transport power on the Intertie.

Section 4.2 New Participant

An entity seeking Participant status shall execute a New Participant Addendum to this Agreement in the form attached as Exhibit C, and such other agreements as may be required by the IMC from time to time. The entity shall also be required to execute a User Agreement to have the right to transport power on the Intertie. The entity shall then give twenty-four (24) months written notice to AEA and the Participants of its intention to become a Participant. The entity shall become a Participant upon expiration of the twenty-four (24) month notice period required in this section and the IMC's determination that all of the requirements of this Agreement have been completely satisfied. The IMC's determination under this section shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

Section 4.3 Membership in IMC

An entity with Participant status shall be allowed, but not required, to appoint one member to the IMC. IMC members' voting rights shall be as provided in Article 8, INTERTIE MANAGEMENT COMMITTEE.

Article 5.
WITHDRAWAL OF AEG&T AND OTHER PARTICIPANT AND USER STATUS

Section 5.1 Withdrawal of AEG&T

Notwithstanding the provisions of Section 2.2, Termination, AEG&T shall effect the termination of its Participant status under this Agreement immediately upon its execution of this Agreement.

Section 5.2 Substitution of HEA and MEA, and Admission of City of Seward and the United States Army

Notwithstanding the provisions of Section 4.2, New Participant, HEA and MEA individually shall have the right to obtain Participant status immediately upon their execution of a New Participant Addendum in the form attached as Exhibit C, provided, however, that this right shall terminate twenty-four (24) hours after the termination by AEG&T pursuant to Section 5.1, Withdrawal of AEG&T. The City of Seward and the United States Army shall also have the right to obtain Participant status immediately upon execution of a New Participant Addendum in the form attached as Exhibit C if such execution occurs within twenty-four (24) hours of the execution of this Agreement by AEA and the Participants. In the event that United States Army has not obtained Participant status, then after July 2013, the United States Army shall have the right to become a User by executing a User Agreement and providing three (3) months written notice to the IMC, so long as the available Intertie Capacity is not fully subscribed.

Article 6.
MINIMUM RIGHTS OF THE PARTICIPANTS AND USERS TO USE INTERTIE FACILITIES

Section 6.1 Minimum Intertie Transfer Capability Rights ("MITCR")

The established MITCR rights as well as the MITCR methodology for allocation of Capacity on the Intertie from the Original Agreement are temporarily retained in this Agreement and shall be administered by the IMC during the period from the Effective Date until July 1, 2013. The MITCR methodology is set forth in this Article 6. The IMC shall implement a new methodology for allocation of Capacity before July 1, 2013, which shall comply with the provisions of Article 16, OPEN ACCESS PRINCIPLES.

6.1.1 Right of First Refusal. For so long as the IMC has not amended or replaced the MITCR methodology, Participants shall have the right of first refusal to an allocated portion of the maximum Intertie transfer capability, as determined pursuant to Section 6.2, Determination of MITCR. Intertie Capacity not scheduled or used by the Participants for the purpose of transmitting or receiving Energy over the Intertie shall be allotted to the Participants in the manner provided in Section 6.2.2, Unused MITCR.

6.1.2 Allocation of Transfer Capability. The Intertie transfer capability shall be shared by the Participants in the Northern and Southern Groups in the manner described in Section 6.2, Determination of MITCR. If a Participant is not using part of its MITCR in either direction, other Participants shall have the right to use that unused part to make transfers across the Intertie, either as a purchase or a sale of Capacity and/or Energy, pursuant to a procedure adopted by the IMC.

6.1.3 Emergency Operations. During emergencies when it is necessary to use the Intertie to transfer Energy to maintain system integrity, a Participant's MITCR

will be adjusted by the IMC as required pursuant to Intertie operating policies and procedures and Prudent Utility Practices. To the extent practical, such adjustments shall be shared proportionally among all Participants in the affected Group(s).

Section 6.2 Determination of MITCR

6.2.1 Methodology. For so long as the IMC has not amended or replaced the MITCR methodology, the IMC shall determine the MITCR of each Participant each year prior to the final approval of the fiscal year budget, or when a new Participant becomes a Party to this Agreement. The MITCR of each Participant shall be calculated as follows:

> MITCR shall be determined each year based on the average of the three most recent Annual System Demands submitted by each of the Participants under Section 7.2.1, Participant and User Estimates, Participant Historical Data. Temporary reductions of the maximum Intertie transfer capability may be required for periods due to maintenance, safety, or equipment failure. MITCR shall be determined separately for the Participants of the Northern Group and of the Southern Group. A Participant's MITCR shall be the ratio of its average Annual System Demand to the sum of the average Annual System Demands of its respective group (Northern or Southern) multiplied by the maximum Intertie transfer capability set forth in Section 6.3, Maximum Intertie Transfer Capability.

6.2.2 Unused MITCR. MITCR not used by a Participant shall be available to the other Participants in the same group (*i.e.*, Northern Group or Southern Group) in the same proportion as remaining Participants' MITCR is to the total MITCR of the remaining Participants in the group that are allocating the unused MITCR. If no Participant chooses to use the unused MITCR, the IMC may make it available to any User subject to the requirements set forth in Section 8.6.7, Maximum Capability and Capacity Allocation. Unless otherwise agreed upon, a Participant whose unused MITCR is being used by other Participant(s) or User(s) shall have the right to its full entitlement immediately upon notification to the Participant(s) or User(s) using its MITCR.

6.2.3 Right to Contractually Transfer MITCR. A Participant has the right to transfer on a contractual basis all or part of its MITCR to other Participants or Users with reasonable written notice to all Participants. A Participant whose unused MITCR is being used by another Participant or User under this Section 6.2.3 shall be paid by the using Participant or User a prorated amount of the Intertie Capacity Rate determined by the following formula:

$$P = ICR/12 \times CP \times HR/THR \text{ where:}$$

P - is the monthly payment due to the Participant whose MITCR, or portion thereof, is being used by another Participant or User;

ICR/12 - is the relevant monthly Intertie Capacity Rate as defined in Section 7.2.6, Capacity Rate, of this Agreement;

CP - is the average amount of Capacity in kilowatts which is used by another Participant;

HR - is the number of hours in the month during which the unused MITCR was scheduled by another Participant or User; and

THR - is the total number of hours in the relevant month.

6.2.4 IMC Authority to Change Capacity Allocation Methodology. The IMC shall have the authority to amend or replace the Intertie Capacity allocation methodology with a different methodology. Any amendment or replacement of the Intertie Capacity allocation methodology shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA. In amending or replacing the Intertie allocation methodology, the IMC shall employ Open Access principles to the extent practicable.

6.2.5 New State Power Projects. The IMC shall amend or replace the Intertie Capacity allocation methodology if requested by AEA to facilitate the transfer of power from a new state-owned generation project, provided, that the then-existing rights of Participants and Users for firm service shall be preserved.

Section 6.3 Maximum Intertie Transfer Capability

The maximum transfer capability of the Intertie is 78 MW, net of losses, unless and until it is changed pursuant to this section. No provision of this Agreement shall prohibit the IMC from temporarily reducing the maximum Intertie transfer capability for maintenance, equipment failure, safety considerations, or other reasonable causes in compliance with Prudent Utility Practices. Such temporary reductions of maximum Intertie transfer capability shall proportionally reduce the rights of each Participant and User, for that temporary period. The IMC, upon the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA, shall have the authority to change the maximum Intertie transfer capability.

Section 6.4 Improvements to the Intertie

6.4.1 Development of Improvements. Modifications, additions, deletions and changes to the Intertie ("Improvements") shall be designed and constructed so as not to reduce the Intertie's reliability. All Improvements shall be implemented in accordance with Prudent Utility Practice and, with commercially reasonable consideration of the costs and benefits of such improvements.

6.4.1.1 Except as provided in Section 6.4.1.2, the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA, shall be required to approve any Improvements. The design and specifications, including engineering studies for proposed Improvements to the Intertie shall be submitted to the IMC for review and approval. The IMC may require additional studies. Approval of the design and specifications of Improvements shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

6.4.1.2 AEA shall have the right to make Improvements to the Intertie, including taps to provide electrical services at locations that AEA deems beneficial and reasonable. Costs related to Improvements covered by this Section 6.4.1.2 will not be deemed to be Intertie Costs unless such Improvements are of direct benefit to the Participants and/or Users as determined in advance by the IMC under Section 6.4.3, Responsibility for Cost of Improvements. The design for such Improvements shall be submitted to the IMC for review and comment. The comments of the IMC shall be incorporated into the design of the Improvements as they relate to maintaining the Intertie's reliability.

6.4.1.3 The IMC shall not unreasonably delay the implementation of any Improvements provided for under Section 6.4, Improvements to the Intertie.

6.4.2 Requests for Improvements. Participants and Users, individually or otherwise, shall have the right to request the IMC to make Improvements.

Each request shall include a detailed written explanation of the requested Improvement and demonstrate its compliance with the requirements of Section 6.4.1, Development of Improvements.

6.4.3 Responsibility for Cost of Improvements. The cost of Improvements may be apportioned among the requesting Participants and Users pursuant to a written agreement and may be adjusted to include other sources of funding. If there is no such written agreement, an Improvement shall be made at the expense of the requesting Participant(s), User(s), and/or AEA (AEA only if the Improvement is undertaken pursuant to Section 6.4.1.2) unless the IMC determines prior to performing the Improvement that the Improvement directly benefits other Participants or Users, or may provide direct benefit to other Participants or Users in the future, in which case the cost of the requested Improvements shall be deemed Intertie Costs. The IMC may also, but shall not be required to, determine that the cost of an Improvement shall be born only by the group of directly benefitted Participant(s) or User(s) if some will not be directly benefitted. The IMC shall have the right to consider the cause or need for any Improvements when making its determination of cost responsibility. The IMC shall also determine prior to performing the Improvement whether the cost of such Improvements shall be recovered in the Intertie Energy Rate or in the Intertie Capacity Rate. AEA shall be the owner of all Improvements without regard to the sources of funding. The determination and setting of the responsibility for payment of costs associated with an Improvement and any allocation of recovery between the Intertie Energy Rate and the Intertie Capacity Rate shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

6.4.4 Right to Make Improvements – Required Work. AEA shall have the right to require Improvements to the Intertie as provided in Section 8.8, AEA's Ability to Perform Required Work.

6.4.5 Notice. The IMC shall give reasonable advanced notice to all Participants before approving any Improvements as provided in this Article 6.

Section 6.5 Additional Project Taps

Terms and conditions applicable to new taps and interconnections for new projects shall be subject to, and shall be handled in accordance with, the rules, Reliability Standards, and procedures in effect at the time the tap or interconnection is constructed and as they may be amended from time to time. This Section shall also apply to proposed temporary taps or interconnections.

Article 7.
COSTS FOR INTERTIE TRANSFER RIGHTS

Section 7.1 Intertie Costs

7.1.1 Costs to Be Shared by Participants and Users. Costs incurred in operating and maintaining the Intertie and the annual debt service on any bonds or other debt issued by AEA or contractual obligations incurred by AEA or the IMC for the Intertie facilities, including those incurred for renewals, replacements, repairs, Required Work, and Improvements, ("Intertie Costs") shall be shared by the Participants and Users. Intertie Costs shall be identified in accordance with the provisions of former Alaska Statute 44.83.398(f) (attached as Exhibit D) and this Agreement. Participants and Users shall also contribute to the recovery of Intertie Costs through rates and charges approved by the IMC. At a minimum, the following costs shall be included in Intertie Costs:

7.1.1.1 "Operation and Maintenance Costs" are all operation costs as provided for in Article 10, OPERATION OF THE INTERTIE, and all maintenance costs as provided for in Article 12, MAINTENANCE OF THE INTERTIE FACILITIES, and including any replacements in the ordinary course of operations, plus any applicable taxes, but excluding uninsured losses or liability resulting from deductible or self-insured retention provisions of property or liability insurance policies, respectively.

7.1.1.2 "Extraordinary Maintenance and Replacement Costs" are uninsured losses or liabilities resulting from deductible or self-insured retention provisions of property or liability insurance policies, costs of facility maintenance, renewals, and replacements.

7.1.1.3 "Annual Debt Service Cost" is interest on, and amortization sufficient to retire over their term, any bonds or other debt issued by AEA for construction, renewals, replacement, repairs or Improvements of the Intertie facilities, plus the debt service coverage or other financial performance factors determined by AEA to be necessary for the marketability of bonds issued by it and as provided in any bond covenants, resolutions or similar obligations.

7.1.1.4 "Reserve Fund" is the amount necessary, as determined by the IMC, to provide a prudent level of reserves to fund the operation and maintenance of the Intertie and the Intertie Costs specified in this Section 7.1, Intertie Costs. The Reserve Fund shall be maintained as a separate and distinct fund to be held, managed, invested, disbursed and administered by AEA in accordance with criteria approved by the affirmative vote of a

minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA. All money deposited in the Fund shall be used solely for the purposes set forth in this Agreement. AEA shall keep and maintain records pertaining to the Reserve Fund, and all disbursements therefrom, in accordance with its general practices and procedures in effect from time to time and in compliance with GAAP.

7.1.1.5 Station service costs.

7.1.1.6 "Cost of Improvements" those costs determined in accordance with Section 6.4.3, Responsibility for Cost of Improvements.

7.1.2 Annual Budget and Fiscal Year. The IMC will estimate and budget Intertie Costs annually for the ensuing fiscal year, July 1 to June 30, subject to AEA's review and approval. The IMC shall develop annually a preliminary operating budget from: the Intertie maintenance budget; the Intertie operating budget; the Annual Debt Service costs; and, AEA's administrative expense associated with the Intertie. Unless otherwise agreed in writing by the Participants, the preliminary Intertie budget shall be provided to the Participants and made available to the public for their review at least thirty (30) days before the IMC meeting where the budget will be approved. Written comments shall be submitted to AEA and the IMC by the date established by the IMC. The Participants shall be provided no less than thirty (30) days to comment. Based on the preliminary Intertie budget and the comments from the Participants, the IMC shall annually establish the Intertie operating budget and submit it to the AEA for review and approval.

Section 7.2 Calculation of Intertie Costs and Rates

7.2.1 Participant and User Estimates. Participant Historical Data. The IMC shall establish a schedule and format that the Participants and Users with valid contracts for service on the Intertie shall use to submit their projected usage of the Intertie for the upcoming fiscal year. Unless directed to do otherwise by the IMC, Participants and Users shall also submit, at the same time, their three most recent Annual System Demands for the calculation of MITCR under Section 6.2, Determination of MITCR, or as required by the IMC for the allocation of Intertie Capacity.

7.2.2 IMC Estimates. The IMC shall prepare a preliminary Intertie annual usage estimate in kilowatt hours ("kWh") and provide the same to the Participants and Users no later than the date the preliminary Intertie budget is submitted to the Participants for comment. The preliminary Intertie annual usage estimate provided under this Section with the use of projected or other relevant

information shall in no event be less than the amount equal to 30 percent of the kWhs that could be transferred by continuous operation of the Intertie at the maximum rated fiscal-year transfer Capacity (as currently established under Section 6.3, Maximum Intertie Transfer Capability). The projected usage shall not exceed the total projected usage of the Participants and Users so long as their combined usage is in excess of the 30 percent as provided in this Section 7.2.2.

7.2.3 Comments. Participants and Users may provide comments to the IMC on the preliminary Intertie annual usage estimate, which shall be considered by the IMC in making its final estimate for the following fiscal year.

7.2.4 IMC Determination of Estimated Intertie Usage. Based upon the Participants' and Users' preliminary Intertie annual usage estimates and comments received, the IMC shall establish the estimated annual Intertie usage in kWhs for the following fiscal year.

7.2.5 Energy Rate. The "Intertie Energy Rate" for the following fiscal year, expressed in dollars per kWh, shall be calculated by dividing 83.5 percent of the total budgeted Intertie Costs as determined in the Intertie budget under Section 7.1, Intertie Costs, by the annual Intertie usage as established under Section 7.2.4, IMC Determination of Estimated Intertie Usage.

7.2.6 Capacity Rate. The "Intertie Capacity Rate" for the following fiscal year, expressed in dollars per kW, shall be calculated by dividing 16.5 percent of the total budgeted Intertie Costs as determined in the Intertie budget established under Section 7.1, Intertie Costs, by the sum of the Participant's or User's Intertie Capacity rights allocations.

Section 7.3 Allocation of Intertie Costs

7.3.1 Participant and User Payments. Each Participant and User shall be obligated to pay to AEA, for the account of the IMC, monthly the sum of the following:

7.3.1.1 The Participant's or User's scheduled use of the Intertie for the month multiplied by the Intertie Energy Rate in effect for the fiscal year; plus,

7.3.1.2 The Participant's Intertie Capacity rights allocation, determined in accordance with this Agreement, multiplied by one-twelfth of the Intertie Capacity Rate in effect for the fiscal year or the Participant's obligation as calculated pursuant to Section 6.2.3, Right to Contractually Transfer MITCR, if applicable; plus,

7.3.1.3 Each User's Intertie Capacity rights allocation, determined in accordance with this Agreement, multiplied by the monthly Intertie Capacity Rate in effect for that period multiplied by the number of months of the fiscal year that the User has a contract for the use of Intertie Capacity or as determined pursuant to Section 7.3.1.2.

7.3.2 Annual Payment of Intertie Costs. The IMC shall have the authority to convert the Participants' and Users' payment obligation, or any portion thereof, to one annual payment, which shall be due and payable at the beginning of the fiscal year. Any such annual payment shall be based on each Participant's or User's projected use of the Intertie to the extent usage has not been scheduled.

7.3.3 Monthly Use. For billing purposes only, the scheduled use of the Intertie in any month shall be the greater of the actual energy transferred or the product of the scheduled Intertie transfer at the Intertie Point of Interconnection and the number of hours each schedule was in effect during that calendar month.

7.3.4 Excess Revenues. Should the annual revenues received from all sources under Section 7.3.1, Participant and User Payments, exceed actual annual Intertie Costs, the revenues in excess of the Intertie Costs shall be allocated to the contributing Participants and Users in proportion to the total dollar amount paid by all parties for use of the Intertie in the fiscal year, or portion thereof, in which the revenues were accrued. The IMC shall authorize AEA to refund the Participants and Users their proportionate share of this excess.

7.3.5 Revenue Deficiencies. Should the revenues received under Section 7.3.1, Participant and User Payments, be less than the actual Intertie Costs, the revenue deficiency shall be allocated between the Participants and Users in the same proportional manner as revenues are re-allocated between the Participants and Users under Section 7.3.4, Excess Revenues, of this Section. The IMC shall authorize AEA to bill the Participants and Users their proportionate share of this deficiency.

Article 8.
INTERTIE MANAGEMENT COMMITTEE

Section 8.1 Establishment of the Intertie Management Committee, Right to Vote

AEA and the Participants hereby establish an Intertie Management Committee. The IMC shall be the governing body with the authority to control, operate, maintain, repair, and perform Improvements of the Intertie in accordance with the terms of this Agreement. The IMC shall consist of the representative appointed by AEA and the representatives appointed by each of the Participants, which shall be either their Chief Executive Officer, General Manager, or Executive Director. Each Participant shall be entitled to only one representative, appointed pursuant to

Section 4.3, Membership in IMC, and one vote on the IMC. AEA shall also be entitled to only one representative and one vote on the IMC. Under no circumstances shall AEA or a Participant have, or have the right to control, more than one vote on the IMC or have more than one voting representative, directly or indirectly, through another organization with which it is an affiliate or has an agency relationship. Each IMC member entitled to vote may name one representative to serve on the IMC and one designated alternate for that representative. A representative or designated alternate may be an employee of a Designated Contractor of the IMC Member. Each IMC member shall notify all other IMC members in writing of the names, addresses, and telephone numbers of its representative and designated alternate. After it is established, the IMC shall meet at least twice each year. Meetings of the IMC and any committees of the IMC shall, to the extent practicable, be open to the public.

8.1.1 Eligibility to Vote. Participants that are not current on their financial obligations for Intertie Costs or any other costs or assessments approved by the IMC shall not be eligible to vote on matters before the IMC and shall not be considered a member of the IMC for purposes of voting, or for calculating the Annual System Demand of Participants or Users for purposes of allocating Intertie Capacity.

8.1.2 Minutes. Written minutes shall be kept for all meetings of the IMC, and all decisions or agreements made by the IMC shall be reduced to writing, including all matters voted upon and each member's vote on those matters.

Section 8.2 Adoption of Procedural Rules or Bylaws

The IMC shall adopt and maintain rules and procedures governing the operation of the IMC ("IMC Bylaws"). The IMC Bylaws shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA, to be effective. The IMC Bylaws shall address, among other matters, procedures for the selection of IMC officers, the conduct of IMC meetings, the approval or possible pre-approval of consultants, the modification of the IMC's procedural rules, and to the extent not otherwise specified in this Agreement, the specific voting requirements for approval of matters to be decided by the IMC.

Section 8.3 Effect of Abstention. For purposes of voting on any matter before the IMC, each abstaining Participant or AEA Representative shall not be counted towards any voting requirement. The minimum percentage required to transact business shall be determined from the total number of IMC Members not abstaining.

Section 8.4 Meetings by Electronic Communication. The IMC may elect to meet by electronic communication so long as all members can be heard and hear all of the proceedings.

Section 8.5 IMC Responsibilities

8.5.1 IMC Responsibilities and AEA Duties. AEA, as the legal owner of the Intertie, a potential issuer of debt related to the Intertie, and the agency

charged by statute with various duties affecting or affected by the Intertie, has or may have assigned to it, certain rights, duties, and responsibilities with respect to the Intertie. For example, AS 44.83.396(e) imposes on AEA the duty to (a) review and approve the annual budget for the operation and maintenance of the project, and (b) assure that the project is being operated efficiently and in a manner that is consistent with national standards for the industry and agreements with any bondholders. (See also, Section 8.8, AEA's Ability to Perform Required Work.) Subject only to such AEA rights, duties, and responsibilities, the IMC shall be responsible for the management, operation, maintenance, and improvement of the Intertie. The IMC members, Participants, and Users are the beneficiaries of the prudent management of the Intertie and shall bear their respective share of Intertie Costs in accordance with the terms of this Agreement. All Users have a shared and substantial long-term financial interest in the Intertie facilities. The IMC shall undertake responsibility for the prudent management and reliable operation of the Intertie on behalf of AEA, for the benefit of the Participants and Users.

8.5.2 IMC Approvals. IMC approval of the sufficiency of the annual budget, rates, and the allocation of Intertie Capacity, shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

Section 8.6 IMC Actions

The IMC shall have the authority to take the actions set forth in this section, subject only to the provisions of any applicable bond resolutions, federal and state law, the requirements of licensing and regulatory agencies, and the rights of AEA, the Participants, and Users under other provisions of this Agreement.

8.6.1 Intertie Operation. Develop, adopt, and enforce operating policies and procedures and Reliability Standards applicable to the Intertie. See Section 3.1, Adoption of Operating Policies and Procedures, and Reliability Standards.

8.6.2 Intertie User Agreements. Adopt standard terms and conditions for User Agreements for Intertie Transactions in accordance with this Agreement and incorporating Open Access principles. Adopt a three (3) month termination provision in certain User Agreements in accordance with Section 5.2, Substitution of HEA and MEA, and Admission of City of Seward and the United States Army, and Section 16.3.5, Federal Acquisition Regulations.

8.6.3 Non-Compliance Appeals. Provide procedures for Users to appeal: (i) Operating policies and procedures; ii) Reliability Standards non-compliance determinations; or iii) sanctions imposed for non-compliance with Reliability Standards.

8.6.4 O&M and Scheduling. Arrange for the operation and maintenance of the Intertie and the scheduling of power transfers on the Intertie.

8.6.5 Budget. Adopt, and revise if prudent to do so, each fiscal year a budget of Intertie Costs for that fiscal year. The adopted or revised budget shall be reasonably estimated by the IMC to be sufficient to pay all Intertie Costs and shall be made available to the puhlic at the time it is distributed to Participants. The IMC shall establish the fiscal year budget in accordance with Article 7, COSTS FOR INTERTIE TRANSFER RIGHTS, and a schedule established by the IMC.

8.6.6 Cost Allocation and Payment Schedule. Establish for each fiscal year the estimated annual allocation of Intertie Costs for each Participant and User together with a schedule for each Participant's and Users' required monthly payments during that fiscal year, pursuant to Sections 7.2, Calculation of Intertie Costs and Rates, and 7.3, Allocation of Intertie Costs. The payment schedule shall be designed to recover the Participant's or User's share of the estimated annual Intertie Costs during the fiscal year and as revised during such Year to reflect any approved changes to the budget of annual Intertie Costs for that fiscal year. The IMC also shall determine the costs to be collected from Users for Intertie Transactions. Such costs shall be determined and applied based upon just, fair, reasonable, and not unduly discriminatory principles and in compliance with Article 16, OPEN ACCESS PRINCIPLES. The approval of the allocation of Intertie Costs, payment schedule, and the costs to be collected for Intertie Transactions shall require the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

8.6.7 Maximum Capability and Capacity Allocation. Establish the maximum Intertie transfer capability in accordance with Section 6.3, Maximum Intertie Transfer Capability. Determine each Participant's and User's rights to Intertie Capacity pursuant to any methodology adopted under Article 6, MINIMUM RIGHTS OF THE PARTICIPANTS AND USERS TO USE INTERTIE FACILITIES. The IMC shall consider the Participant's or User's reserve obligations and equitably preserve any Participant's and User's Intertie operational rights existing as of the Effective Date that are valid and effective at the time of the IMC's determination. The IMC shall have the right to consider the cause or need for such operational rights when making its determination.

8.6.8 Determination of Actual Payment Obligation. Determine after the conclusion of each fiscal year the actual annual Intertie Costs for that fiscal year, the actual annual Payment Obligation of each Participant or User for that fiscal year, and the amount of any additional payment required from or the amount

of any refund to each Participant or User to ensure that the total of all payments received from each Participant or User for each fiscal year is equal to that Participant's or User's actual annual Payment Obligation for the fiscal year, pursuant to Sections 7.3.3, Excess Revenues, and 7.3.4, Revenue Deficiencies.

8.6.9 Funding Methods. Evaluate and select methods of carrying out and funding Improvements, whether by recommending AEA's issuance of bonds or otherwise.

8.6.10 Improvements. Evaluate and approve Improvements and determine the required level of funding for approved Improvements under Sections 6.4.2, Requests for Improvements, 6.4.3, Responsibility for Cost of Improvements, 6.4.4, Right to Make Improvements – Required Work, or as otherwise provided in this Agreement.

8.6.11 Maintenance. Adopt maintenance schedules for the Intertie that do not unreasonably interfere with the operations of the Participants.

8.6.12 Creation of Reserve Fund. Establish and maintain a Reserve Fund, which meets the requirements set forth in Section 7.1.1.4.

8.6.13 Procurement of Services. Procure services the IMC requires so long as sufficient budgeted funds are available for those services and the procedures for such procurements are in compliance with the IMC's Bylaws and any applicable Alaska law or regulation.

8.6.14 Miscellaneous. Provide for all things necessary to carry out the responsibilities and obligations set forth in this Agreement and in the IMC Bylaws.

Section 8.7 Payment Obligation Unimpaired

Notwithstanding any action or inaction by AEA or the IMC under this Agreement, each Participant's or User's obligation to make payments necessary to pay their allocated percentage share of Intertie Costs under Section 7.3, Allocation of Intertie Costs, of this Agreement and all other amounts to be paid under this Agreement ("Payment Obligation") shall be absolute and unimpaired. Each Participant and User shall make all payments as required as a result of action taken by the IMC under this Agreement or an action taken by AEA pursuant to Section 6.4.4, Right to Make Improvements - Required Work, or Section 8.8, AEA's Ability to Perform Required Work.

Section 8.8 AEA's Ability to Perform Required Work

In the event the IMC fails to take any of the actions set forth in this Agreement in a timely fashion or fails to take any other action which the AEA believes to be a required action with

respect to the management, operation, maintenance or improvement of the Intertie, and as a result the AEA determines that it will be unable to meet any of its obligations imposed by bond resolutions, by this Agreement, by any licensing or regulatory agency, or by statute, or as otherwise is necessary to keep the Intertie in good and efficient operating condition, consistent with (1) prudent economics for the Intertie and the Participants and Users, and (2) national standards for the industry ("Required Work") then the AEA may: (a) adopt a budget of Annual Intertie Costs; (b) estimate the Payment Obligation of each Participant in accordance with the methodology set forth in this Agreement; (c) require each Participant to make payments on the basis of such estimated Payment Obligation; or (d) cause the Required Work to be performed; and (e) take such other action as the AEA deems reasonably necessary to meet such obligations. All actions and determinations under this Section 8.8 shall be taken in accordance with Prudent Utility Practice. The comments of the IMC regarding Required Work related to Improvements shall be given great weight and incorporated into the design of the Improvements as they relate to the operation and reliability of the Intertie.

Section 8.9 Payment Obligation and Rights of Review

Making a payment as required under this Agreement shall not constitute a waiver of any of the Participant's or User's rights under this Agreement. Any Participant or User may seek review of actions by the IMC by means of the procedures in Article 19, REVIEW OF DECISION.

Section 8.10 AEA Authority to Collect Payments and Disburse Funds

The IMC hereby delegates to AEA the authority to invoice and collect from Participants or Users any Payment Obligations due and owing under this Agreement and to make payments on behalf of the IMC for Intertie operations, maintenance or other Intertie related expenses arising under this Agreement. AEA shall hold funds collected in one or more separate accounts designated for Alaska Intertie purposes until such funds are obligated for Intertie operations or maintenance and used to pay Intertie Costs. Interest and/or investment income earned on invested funds shall be credited to the IMC. The IMC shall have the right to audit all funds held by AEA on behalf of the IMC as well as the transactions associated therewith.

Article 9.
OPERATING COMMITTEE

Section 9.1 Establishment of the Operating Committee

9.1.1 Establishment. The IMC shall establish a committee for the purpose of recommending operating policies and procedures under the direction of the IMC and assisting in the implementation of any policies and procedures approved by the IMC (the "Operating Committee").

9.1.2 Representatives. Each Participant may, but is not required to, designate a representative to act on its behalf, which shall be done in writing ("Representative"). Such Representatives shall meet the requirements of Section 3.5, Operating Committee. Each Participant may also designate an

alternate who may act in the stead of its Representative at the option of that Participant. A Participant may at any time change, remove or designate its representative or alternate, and shall promptly notify in writing the other Participants of any change in such designation. The members of The Operating Committee shall designate a member to be Chairman Recommendations and decisions of the Operating Committee shall be adopted if approved by at least a majority of the Representatives appointed under this Section, unless otherwise provided in the bylaws of the committee. The AEA may designate a Representative to the committee who may vote on any matters.

Section 9.2 Meetings of the Operating Committee

9.2.1 Meetings. The Operating Committee shall meet at least once each year and at such other times as deemed necessary by its Chairman or the IMC and shall to the extent practicable, be open to the public.

9.2.2 Voting. The Operating Committee may determine the manner of voting on matters that come before it. All decisions of the Operating Committee affecting the Participants, the Intertie, or its Users shall be subject to the review and approval of the IMC.

9.2.3 Minutes. Written minutes shall be kept for all meetings of the Operating Committee, and all decisions or agreements made by the Operating Committee shall be reduced to writing including all matters voted upon and each member's vote on those matters.

9.2.4 Expenses. The Operating Committee shall prepare and submit an expense budget to the IMC under Section 10.3, Budget for Operation of the Intertie, annually to provide for Operating Committee expenses other than the expenses of each Operating Committee Representative, which shall be borne by the Operating Committee Representative.

9.2.5 Meetings by Electronic Communication. The Operating Committee may elect to meet by electronic communication so long as all members can be heard and hear all of the proceedings.

Section 9.3 Operating Procedures

The Operating Committee shall recommend operating policies and procedures and standard practices to the IMC for the guidance of dispatchers and other employees and shall recommend arrangements for metering, communications, and other services and facilities. All such operating policies and procedures and standard practices shall be subject to the approval of the IMC pursuant to Section 3.1, Adoption of Operating Policies and Procedures, and Reliability Standards, and shall conform with any Reliability Standards adopted by the IMC. The Operating

Committee has no authority to modify any of the provisions of this Agreement or to modify or set rates for Intertie services.

Article 10.
OPERATION OF THE INTERTIE

Section 10.1 Responsibility for Operation of the Intertie

10.1.1 Responsible Participants. AML&P and GVEA are hereby delegated the responsibility for the operation of the Intertie on behalf of the IMC. The operation of the Intertie shall be in compliance with the guidelines of this Agreement, the operating policies and procedures established by the IMC, and in compliance with any applicable Reliability Standards. The IMC may at any time designate another Participant to assume such responsibility from GVEA or AML&P with the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA. Upon such designation by the IMC, the name of the new operator(s) shall be deemed substituted for the name of the old operator(s) in this Article 10, OPERATION OF THE INTERTIE, as appropriate.

10.1.2 AML&P and MEA Responsibilities. AML&P shall be responsible for the operation of the southern assets of the Intertie including, but not limited to, coordination with other utilities, the terminal facilities, communication facilities, the Intertie transmission line, and other facilities south of the Douglas Substation (more specifically illustrated and defined in the Intertie Facilities Diagram in Exhibit E of this Agreement). The Douglas Substation Intertie facilities shall be managed by AML&P and shall be deemed to be the point of demarcation between the Intertie Operators.

10.1.2.1 AEA has contracted with MEA under the 1984 Joint Use Agreement for use of approximately five and one-half (5.5) miles of MEA's right-of-way and constructed transmission facilities that are a part of the Intertie to the Teeland Substation. This being presently a part of the Intertie, the IMC delegates to AML&P, and AML&P assumes the responsibility for operation of this portion of the transmission facilities. AEA delegates to MEA and MEA assumes responsibility for maintenance of this portion of the transmission facilities. Nothing contained in this Agreement shall be deemed to modify any portion of the 1984 Joint Use Agreement.

10.1.3 GVEA Responsibilities. GVEA shall be responsible for the operation of the northern assets of the Intertie, including but not limited to, coordination with other utilities, the terminal facilities, communication facilities, the Intertie transmission line, and other facilities north of the Douglas Substation (as more

specifically illustrated and defined in the Intertie Facilities Diagram in Exhibit E of this Agreement). The Douglas Substation Intertie facilities shall be managed by AML&P and deemed to be the point of demarcation between Operators.

10.1.4 Joint Responsibilities. AML&P and GVEA acting in concert shall:

10.1.4.1 Coordinate all the activities and transactions involving the Intertie operation;

10.1.4.2 Coordinate Intertie Transactions to ensure that at all times, to the extent possible, the Intertie System is operated to: provide reliable and economical service; optimize the availability of the Intertie within practical operational and cost constraints; and; ensure the Intertie is fully subscribed;

10.1.4.3 Comply with, monitor compliance with, and enforce the operating policies and procedures and Reliability Standards;

10.1.4.4 Coordinate the scheduling of all Intertie Transactions by the Participants in the Northern and Southern Groups in accordance with the provisions of this Agreement, and inform all Participants of the scheduled transactions;

10.1.4.5 Develop procedures for restoration of service on the Intertie for interruptions due to either Scheduled or Forced Outages, and have personnel trained to carry out such operational procedures to ensure Intertie reliability;

10.1.4.6 Maintain communications with each other and the other Participants using prudent methods of data acquisition sufficient for reliable system control of the operation of the Intertie;

10.1.4.7 Maintain complete and accurate hourly records of all operations, Intertie Transactions, and activities involving the Intertie, and promptly publish and distribute such records to all Participants at regular intervals as established by the Operating Committee (any Participants who desire it shall be provided, at their own expense, direct access to all telemetry gathered from the Intertie);

10.1.4.8 Coordinate the responsibilities delegated to them in this Agreement to minimize duplication and ensure efficient operation of the Intertie;

10.1.4.9 Abide by the terms and conditions of other contracts or agreements involving the operation of the Intertie, so long as they do not conflict with this Agreement;

10.1.4.10 Operate the Intertie in a safe, reliable, and responsible manner consistent with Prudent Utility Practices, the directives and instructions of the Operating Committee, and any applicable Reliability Standards.

10.1.5 Contracting. The IMC may, to the extent permitted by law, contract with other Participants and qualified contractors to maintain transmission facilities under IMC control.

10.1.6 Load Balancing. The Operating Committee shall recommend operating policies and procedures and standard practices to the IMC to guide load balancing responsibilities performed by the Intertie Operators and any Control Area operators interconnected with the Intertie.

Section 10.2 Suspension of Work in Performance of Operational Duties

The AEA or IMC may order AML&P and/or GVEA, or any other entity responsible for operation of the Intertie, in writing to suspend, delay, or interrupt all or any part of the work involved in operation of the Intertie for such period of time as AEA or the IMC determines to be appropriate for the convenience of, and in the best interest of, the operation of the Intertie.

Section 10.3 Budget for Operation of the Intertie

10.3.1 Budget Process. For purposes of calculation of unit Intertie Costs pursuant to Section 7.2, Calculation of Intertie Costs and Rates, of this Agreement, AML&P and GVEA may develop and submit to the IMC a suggested scope of operations and a budget for operation of the Intertie upon thirty (30) days written notice to the IMC. The budget developed by the Intertie Operators may include all direct expenses and an allocated portion of such other expenses as interest, depreciation and margin requirements, among others. All costs allocated to the Intertie Operator budget shall be consistent with AML&P's and GVEA's respective utility system operations and generally accepted utility accounting principles. Unless otherwise agreed upon, the IMC shall provide AML&P and GVEA submittals to the Participants for their review and comments prior to the inclusion of such costs in Intertie Costs. The Participants shall be provided no less than thirty (30) days to comment.

10.3.2 Participant Comments. Participants may provide written comments on the preliminary scope of operations and related budget requirements to the IMC pursuant to a schedule adopted by the IMC. The Participants shall be provided no less than thirty (30) days to comment.

10.3.3 IMC Establishes Budget. Based on the preliminary scope of operations and budget and the comments received, the IMC shall establish the final Intertie operating budget under the schedule established in Section 8.6.5, Budget.

10.3.4 IMC Determinations and Payment of AML&P and GVEA. If AML&P and GVEA submit a budget under Section 10.3.1, Budget Process, the IMC shall determine the final scope of operations and related budget requirements that will be deemed to be the fixed cost fee for operation of the Intertie for the ensuing fiscal year. Unless otherwise agreed, the IMC shall pay each of AML&P and GVEA pursuant to Section 10.6, Payment of Operators.

10.3.5 Payment if IMC Unable to Determine Fixed Cost Fee. If the IMC is unable to determine the fixed cost fee for operation of the Intertie, then AML&P and GVEA may each determine, using records and accounts maintained under Section 10.4, Accounting and Records, the cost to their respective systems to provide operation of the Intertie in accordance with this Agreement and shall bill the IMC monthly for these services. The IMC will then reimburse AML&P and GVEA under Section 10.6, Payment of Operators.

Section 10.4 Accounting and Records

In maintaining accounts for operation of the Intertie, AML&P and GVEA will follow the system of accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission, conform to Section 12.2.2, Cost Records, and GAAP. AML&P and GVEA will furnish the IMC such operating and financial statements relating to operation of the Intertie as may be reasonably requested by AEA or the IMC. If receipt of such operating and financial statements is unduly delayed, the IMC may, with its own staff, perform all work necessary to collect such data as reasonably necessary. Such work shall be performed at a time and in a manner to prevent unreasonable interference with AML&P and GVEA operations.

Section 10.5 Audits

10.5.1 Request for Audit. At the discretion of AEA or the IMC or by request of a majority of the Participants, an audit shall be conducted with respect to the matters provided for in this Agreement by independent auditors according to such programs and procedures as agreed to by the Participants, and all Participants shall be furnished copies of the report. The cost of performing such audits shall be shared by the Participants in the same proportion as their MITCR or share of Intertie Capacity share during the period covered by the audit or as determined by the IMC. The Participants, their agents, and any other party involved with the operation of the Intertie, shall provide and/or make available the information and records required for the audit. The cost of any audit required by a Participant that is beyond the above scope deemed necessary by the IMC shall be borne by such Participant.

10.5.2 State Audit. AML&P and GVEA shall allow their books of accounts to be audited with respect to matters provided for in this Agreement by such state officials or agencies as may be authorized and directed by law to make those audits. To the extent permitted by law, Participants shall have the same authority to audit the books of accounts of the IMC and AEA with respect to the operation of the Intertie.

Section 10.6 Payment of Operators

If a fixed cost fee for operation of the Intertie is established under Section 10.3.4 of this Article, then within thirty (30) days of the end of each month the IMC shall pay to AML&P and GVEA one-twelfth of their respective yearly fixed cost fees for operation of the Intertie. If the Participants have not agreed upon a fixed cost fee for operation of the Intertie under Section 10.3.4 of this Article, then the IMC shall reimburse AML&P and GVEA within thirty (30) days of the receipt of their invoices. At all times, however, such reimbursement is subject to adjustment in the event of errors, the resolution of disputes, or as the result of audit findings.

Section 10.7 Change in Ownership or Control

If there is any change in the ownership, ownership structure, control of, or right to control an entity delegated responsibility for the operation of the Intertie on behalf of the IMC, or any such change regarding an entity delegated any other responsibility related to the operation or maintenance of any portion of the Intertie facilities, then the IMC may designate another Participant, or such other entity as it deems appropriate, to assume those responsibilities. The IMC's designation shall be accomplished in the same manner as set forth in Section 10.1.1, Responsible Participants.

Section 10.8 Critical Repairs and Maintenance

In the event that immediate action is required to preserve the reliability or safe operation of the Intertie, the operators shall have the right to engage qualified contractors or qualified members of their own staff to effect such repairs as are reasonably necessary pursuant to Prudent Utility Practices. The costs for such repairs shall be Intertie Costs. In the event an Operator has not performed, or cannot perform, repairs or maintenance on Intertie facilities for which it is responsible, and such delay or failure jeopardizes the immediate safety, reliability, or operation of the Intertie pursuant to Prudent Utility Practices, the affected Participants shall have the same right to effect such repairs or maintenance. The costs for such repairs or maintenance shall be Intertie Costs.

Article 11.
SCHEDULING OF CAPACITY AND ENERGY ON THE INTERTIE

Section 11.1 Scheduling Responsibility

11.1.1 Southern Group. AML&P shall have the responsibility for scheduling transfers on the Intertie for the Participants and Users of the Southern Group

and coordinating them with GVEA under: (i) the provisions of this Agreement; (ii) any operating policies and procedures or Reliability Standards; and (iii) the procedures adopted by the IMC.

11.1.2 Northern Group. GVEA shall have the responsibility for scheduling transfers on the Intertie for the Participants and Users of the Northern Group and coordinating them with AML&P under: (i) the provisions of this Agreement; (ii) any operating policies and procedures or Reliability Standards; and (iii) the procedures adopted by the IMC.

11.1.3 Coordination. AML&P and GVEA shall each have the responsibility for coordinating schedules within their respective Groups.

Section 11.2 Capacity and Energy Schedules

11.2.1 Participant Hourly Schedules. The amount of electric Capacity used and Energy to be transferred on the Intertie under this Agreement will be based upon hourly schedules provided by the Participants and Users.

11.2.2 Advanced Scheduling. Capacity and Energy shall be scheduled on an hourly basis and the schedules may be made for the next hour(s), day(s), week(s), or month(s) in advance if allowed by the operating policies and procedures.

11.2.3 Procedure. Schedules for all transfers on the Intertie shall be furnished to the respective Intertie Operators before 3:00 P.M. prevailing local time each day for Capacity used and Energy to be delivered across the Intertie for each clock hour of the following 24-hour period. If the IMC determines that it is prudent to do so, this schedule shall be updated each day and an additional six-day schedule will be furnished to provide a continuing seven-day schedule.

11.2.4 Short-term Scheduling. Short-term schedules of transfers on the Intertie may not be made or changed on an hour-by-hour basis unless coordinated in advance with the Intertie Operators. Operators will use their best efforts to accommodate changes.

11.2.5 Modification of Scheduling Procedures. Modifications to scheduling procedures shall be required to be adopted by the IMC before implementation to be effective.

Section 11.3 Intertie Schedule Limitations

The maximum schedule of Capacity and Energy of any Participant or User on the Intertie shall be limited to their individual Intertie Capacity rights as allocated under this Agreement, either by the MITCR methodology or the methodology adopted by the IMC under Section 6.2.4, IMC Authority to Change Capacity Allocation Methodology.

Section 11.4 Transmission Service to Access the Intertie

Each Participant and User shall have the sole responsibility for scheduling any service(s) required, on the intervening transmission systems for transfers of Energy or Capacity to and from the Alaska Intertie, in compliance with the applicable tariff schedules of the Participants or utilities involved.

Article 12.
MAINTENANCE OF THE INTERTIE FACILITIES

Section 12.1 Maintenance Responsibility

12.1.1 Responsibility for Maintenance Practices. The IMC shall maintain the Intertie facilities that AEA owns or for which AEA has contracted use arrangements. The IMC shall provide for the maintenance of the Intertie facilities by contracting with qualified parties to perform maintenance on its behalf. Maintenance shall be scheduled, coordinated, and accomplished in accordance with Prudent Utility Practices so as to minimize disturbances on the Intertie that would impair service on the Participants' systems.

12.1.2 Availability. The Intertie shall be maintained in good working condition, optimizing the availability of the Intertie within practical operational and cost constraints. After a failure on the Intertie, the Intertie shall be returned to service in the shortest possible time within the constraints of practical maintenance procedures and Prudent Utility Practices.

Section 12.2 Maintenance Budget and Costs

12.2.1 Development of Budget. The IMC shall develop an annual maintenance budget and a schedule for the maintenance on the Intertie each year based on the budgets developed by the contractors providing Intertie maintenance. This budget will be reviewed with the Participants and Users sufficiently in advance of the commencement of the fiscal year covered so that each Participant or User will be able to submit its comments for consideration prior to finalization of the budget. Budgets for more than one year will be required for the Participants' and Users' long range fiscal planning requirements. The IMC will prepare and furnish the Participants and Users a copy of the long range fiscal requirements for the Intertie, or a forecast of such requirements.

12.2.2 Cost Records. AEA, in cooperation with the IMC, shall maintain complete and accurate records of costs associated with maintenance of the Intertie. Costs associated with maintenance of the Intertie will be recorded using the system of accounts prescribed for public utilities and licensees by the Federal Energy Regulatory Commission.

Article 13.
MEASUREMENT OF ELECTRIC POWER AND ENERGY

Section 13.1 Required Metering Facilities

The electric power delivered through interconnection facilities of the Intertie shall be measured by nonreversible watt-hour meters and 15-minute interval demand meters.

Section 13.2 Access to Metering Facilities and Data

The IMC is responsible for the operation and maintenance of the facilities necessary to interface with points of interconnection. The equipment at these points of interconnection is necessary to provide for Intertie operation only. The IMC shall provide for the use of available metered Intertie data output for Participants or Users for the purpose of providing data necessary for their operations.

Section 13.3 Installation and Maintenance

The IMC shall agree upon the specifications for Intertie-related metering equipment before its installation. Each Participant hereby grants to all other Participants the right to install and maintain at the installing Participants' cost, Intertie-related equipment in other Participants' substations. Each Participant has the right to install and maintain, at its cost, equipment in another Participant's substation only if the equipment is necessary to perform Intertie functions under this Agreement. The installation and maintenance shall be coordinated with staff of the Participant owning and operating the facilities on which the meters are to be installed. Ingress and egress shall be granted to the other Participants to install, remove, or maintain such equipment. Participants shall coordinate such activities.

Section 13.4. Testing of Metering Equipment.

Participants, Users, and AEA, shall each, at its cost, have the right to require testing of metering equipment for accurate registration by a qualified third party. Such testing shall be coordinated with the Participant owning and operating the facilities on which the meters are installed. The IMC shall be responsible for taking appropriate action to resolve any inaccurate registration, plus or minus, that is not within tolerances approved by the IMC pursuant to Section 9.3, Operating Procedures.

Article 14.
TRANSMISSION LOSSES

Section 14.1 Intertie Transmission and Transmission Service Losses

14.1.1 Method of Determination of Losses. Losses in the Intertie System created by Intertie transfers shall be determined by the Intertie Operators through engineering studies, calculation, and power flow programs, and procedures as established by the Operating Committee.

14.1.2 Compensation for Losses. The Participant or User supplying Capacity and Energy shall also provide power to compensate for losses which occur from the transfer. Such compensating power shall be provided at the time of the transfer unless otherwise agreed by the affected Participants or Users.

14.1.3 Schedules. Transfer schedules shall include losses associated with such transfers. When transfers reduce losses in a Participant's system which is not a part of the Intertie, the losses in that system caused by the transfer shall be considered zero.

Section 14.2 Intertie Transmission Loss Compensation

Losses occurring due to Energy transfers shall be made up by in-kind deliveries of Energy and scheduled accordingly. All Energy usage that occurs in Intertie facilities within a Control Area will be allocated and charged to the operation of the Intertie in that Control Area. In each month, entities utilizing the Intertie will be allocated losses based on their percentage share of the Energy transferred in their respective Control Area. If no Energy is transferred, losses will be allocated according to MITCR shares.

Article 15.
RIGHTS OF USERS

The rights and responsibilities of a User shall be set out in a User Agreement adopted by the IMC pursuant to Section 8.6.2, Intertie User Agreements. Non-Participant Users shall not be directly responsible for the management, operation, maintenance or improvement of the Intertie, but shall have the same rights, obligations, and responsibilities as a Participant with respect to compliance with operating policies and procedures, any applicable Reliability Standards and the provisions of Section 8.7, Payment Obligation Unimpaired and Article 20, INDEMNITY.

Article 16.
OPEN ACCESS PRINCIPLES

Section 16.1 Definition

"Open Access" means that all potential Users of the Alaska Intertie shall be provided access to transmission service on the Alaska Intertie under common terms and conditions that are just and reasonable and not unjustly discriminatory, subject to a priority reservation of Capacity for power supply contracts with AEA projects, and equal access to Intertie system information the IMC has deemed critical for all potential Users.

Section 16.2 Purpose

The policies and procedures for the operation of the Intertie shall make use of Open Access principles where practicable.

Section 16.3 Implementation of Capacity Allocation Methodology

The IMC shall use the process and principles in this Section 16.3 as guidance when developing a proposed allocation methodology for Intertie Capacity.

16.3.1 New Methodology. The IMC shall develop and implement a methodology for the allocation of Intertie Capacity, approved by AEA pursuant to Sections 6.2.4 IMC Authority to Change Capacity Allocation Methodology, and 8.6.7 Maximum Capability and Capacity Allocation, before July 1, 2013. The methodology shall use and incorporate Open Access and other principles set forth in this Article.

16.3.2 Statutory Conditions. The allocation of Intertie Capacity shall comply with statutory conditions, including that the allocation provide a method by which municipal electric, rural electric, cooperative electric, or private electric and regional electric authorities, or other persons authorized by law to engage in the distribution of electricity may secure a reasonable share of available Intertie Capacity (i.e., United States Army).

16.3.3 Priority for AEA Contracts. Participants or Users with contracts for power from a facility owned by AEA shall have a priority capacity reservation on the Intertie sufficient to accommodate the transfer of that contracted power throughout the term of the power supply contract with AEA. This priority shall be subject to rights of Participants and Users with firm contracts so long as the Participant or User materially satisfies its related obligations. Continued service under firm contracts will be guaranteed irrespective of whether another AEA-owned project is developed or additional transmission capacity is made available by AEA or another entity. In the event that additional transmission capacity is made available, however, the IMC shall have the right to supply transmission service to those Participants or Users by means of transmission paths other than the currently-existing Intertie so long as there is no degradation in the quality or amount of transmission capacity provided.

16.3.4 Alternative Allocation of Intertie Capacity. If the IMC has not developed and implemented a new methodology for the allocation of Intertie Capacity, approved by AEA, on or before July 1, 2013, then the MITCR allocation processes under Article 6 shall continue but in an expanded format. Absent an approved new methodology, after July 1, 2013, and notwithstanding the requirements of Section 4.2, New Participant, any User or potential User shall be entitled to become a "Participant" under and for purposes of Article 6 by (a) giving twenty-four (24) months written notice to AEA and the Participants of its intention to become a Participant under Article 6, and (b) executing a User Agreement, if one has not already been executed. Upon becoming a Participant under this section (referred to as a "Section 16.3.4 Participant) the entity shall obtain full rights to MITCR allocations under Article 6,

MINIMUM RIGHTS OF THE PARTICIPANTS AND USERS TO USE INTERTIE FACILITIES.

16.3.4.1 For purposes of calculating MITCR allocations under Section 16.3.4 and Article 6 for a User eligible to become a Participant only under Section 16.3.4 and that sells wholesale power to an electric utility, the number of "kilowatts-hours in any clock hour, attributable to Energy required during such hour for supply of Energy to a system's consumers," as that phrase is used in the definition of "System Demand," shall include wholesale power sold to an electric utility, unless otherwise agreed in writing by the "Section 16.3.4 Participant." Wholesale power sold to a Participant and included in the calculation of a "Section 16.3.4 Participant's" MITCR may not be included in the calculation of the receiving Participant's MITCR.

16.3.5 Federal Acquisition Regulations. A User Agreement with an organization that is required to follow the Federal Acquisition Regulations (FAR), may differ from the standard User Agreement in order to accommodate obligations to follow the FAR so long as the entity required to follow the FAR has provided the IMC with reasonable assurance that its financial obligations have been or will be satisfied.

Section 16.4 Public Process

The IMC shall publish its initial proposed allocation methodology for Intertie Capacity and request public comment no later than eighteen (18) months after the Effective Date of this Agreement. The IMC shall consider the public comments before finalizing an Intertie Capacity allocation methodology.

Section 16.5 Availability of Information

The IMC shall use a transparent approach to: (i) making Intertie system information available to all Users; (ii) allocating Capacity on the Intertie; (iii) planning for Improvements, planned outages, or increases in Intertie Capacity; (iv) developing the types of transmission service and the setting of the appropriate rate for each type (including ancillary services should it deem the provision of ancillary services appropriate); and (v) budgeting.

Section 16.6 Review of Methodology

The IMC shall request comments on the Capacity allocation methodology in effect once every three years following implementation of the new allocation methodology developed pursuant to Section 16.3, Implementation of Capacity Allocation Methodology.

Article 17.
BILLING AND PAYMENTS

Section 17.1 Billing

Participants and User shall be invoiced monthly for their respective share of Intertie Costs, normally not later than fifteen (15) days after the end of the calendar month to which the bills apply. Bills shall be due and payable within fifteen (15) days from the date the bills are postmarked or hand-delivered. Interest on any unpaid amount from the date due until the date payment is received shall accrue at the annual legal rate under Alaska law for post-judgment interest, or *pro rata* fraction thereof. Interest collected pursuant to this section shall be credited to the IMC.

Section 17.2 Billing Disputes

If a Participant or User disputes the charges on an invoice, the Participant or User shall nevertheless pay the full amount when due and payable and give notification in writing, within ninety (90) days of the date the bill is rendered, to the AEA and IMC stating the grounds on which charges are disputed and the amount in dispute. If settlement of the dispute results in a refund, the refund shall include interest at the annual legal rate under Alaska law for post-judgment interest, or *pro rata* fraction thereof, from the date of overpayment to the date of refund.

Section 17.3 Payment of Sanctions

Any payments related to sanctions shall be administered as provided in any Reliability Standards adopted by the IMC.

Article 18.
INSURANCE AND LIABILITY

Section 18.1 Insurance

During the term of this Agreement, each Participant shall purchase and maintain liability insurance with a carrier or carriers satisfactory to AEA and the IMC covering injury to persons or property suffered by any Participant or a third party as a result of errors, omissions, or operations which arise both out of and during the course of this Agreement by the Participant or by any of its subcontractors, including injuries to all employees of the Participant and the employees of any of its subcontractors engaged in work under this Agreement. If approved by the IMC and AEA, a Participant that is legally eligible to do so may self-insure for the Workers' Compensation Insurance and other types of insurance required by this Article. An insurance certificate in a reasonably satisfactory form or a copy of the insurance policies along with any undertaking to self-insure, shall be furnished to the Operating Committee, AEA and the IMC before beginning operations under this Agreement.

Section 18.2 Types of Insurance

The Intertie insurance coverage and limits shall be reviewed by the IMC yearly and may be adjusted with the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA. The agreed coverage must be provided by each Participant to cover those operations of the Participant performed under this Agreement. The Alaska State Risk Management department may also review the coverage and limits, and any required changes to established coverage and limits shall be adopted.

18.2.1 Workers' Compensation Insurance. Each Participant shall provide and maintain, for all employees of the Participant engaged in work under this Agreement, workers' compensation insurance as required by AS 23.30.045, as it may be amended or replaced, or other Alaska or federal statue or regulation. The Participant is responsible for ensuring that any of its subcontractors who directly or indirectly provide services under this Agreement maintain workers' compensation insurance to the extent required by law. The workers' compensation insurance policy shall contain a waiver of subrogation in favor of the other Participants. Any Participant who is self-insured hereby waives subrogation in favor of the other Participants.

18.2.2 Comprehensive General Liability Insurance. Each Participant shall purchase and maintain comprehensive general liability insurance in an amount not less than the limits approved by the IMC. The other Participants shall be included as additional insureds on insurance required in this Agreement and shall not by their inclusion be responsible to the insurance carrier for payment of premiums therefor. These insurance policies must also contain a cross liability or severability of interest endorsement.

Section 18.3 Other Insurance Coverage Requirements

18.3.1 Participants' Cost Responsibility. Each Participant will bear the cost of the required insurance. Insurance required to be maintained under this Agreement may be maintained as part of any other policy or policies of the Participant so long as the coverage of such policy or policies is substantially the same as if such coverage were maintained under a separate policy.

18.3.2 Users' Insurance Requirements. The IMC may set minimum requirements for Users to be included in any User Agreement for Intertie service.

18.3.3 Coverage and Certificates. These policies must provide that any cancellation, non-renewal, or material change be upon not less than thirty (30) days notice to all named insureds. Each Participant must provide the AEA and IMC with evidence of insurance. Insurance companies or self-insurers shown on the certificate of insurance must have financial ratings acceptable to the AEA.

Failure to furnish satisfactory evidence of insurance or lapse of the policy is a material breach of this Agreement.

Article 19.
REVIEW OF DECISION

Section 19.1 Review of IMC Decision

Participants and Users may seek review of an IMC decision in the manner provided in this Article if they are directly affected by such decision. For review of IMC determinations of compliance or non-compliance with any operating policies and procedures or other IMC adopted standards, a Participant or User first must complete any review process specifically provided for in such policies, procedures, or standards. This Article shall not apply to AEA without AEA's written consent.

Section 19.2 Initiation of Review

Any review process under this Article 19 must be initiated within fifteen (15) days after receipt of written notification of the disputed decision.

Section 19.3 Review Process

19.3.1 Settlement Conference. Within twenty (20) calendar days after the written request of any disputing party, or such longer time as mutually agreed upon, representatives of the IMC and the disputing parties' senior management with direct authority to enter into a settlement agreement shall meet and make a good faith effort to resolve any dispute. In the event the representatives are unable to achieve a resolution, then the dispute shall be subject to mediation pursuant to this Section 19.3. Completion of the settlement conference procedure set out in this paragraph shall be a condition precedent to mediation under this Section unless one or more of the disputing parties refuses to attend the settlement conference as requested.

19.3.2 Disposition of Dispute. Any dispute(s) not resolved by the settlement conference convened pursuant to Section 19.3.1 above, shall be subject to mediation unless otherwise mutually agreed upon in writing. Within twenty (20) calendar days after receipt of a written notice of demand for mediation, or such longer time as mutually agreed upon, the IMC and disputing parties shall jointly select a single, neutral mediator and thereafter shall participate in the mediation in a good faith effort to resolve the dispute(s). If the parties are unable to mutually agree upon a mediator within 20 calendar days after receipt of the written demand for mediation, the mediator shall be selected by the presiding judge of the Superior Court for the Third Judicial District at Anchorage, Alaska, unless mutually agreed otherwise. Any mediator selected must have experience in the subject matter of the dispute. If the IMC and the disputing parties have not reached a settlement of the dispute(s) within an

additional thirty (30) days after appointment of the mediator, or such longer period as they may agree, then they may file an action in a court of competent jurisdiction or pursue such other remedies as they may have.

Article 20.
INDEMNITY

Section 20.1 Responsibility; Cost of Indemnity

20.1.1 Costs of Indemnity. Each Participant shall be responsible for the costs and liability arising out of, or in any way connected with, the acts or omissions of the Participant, its agents (excluding other Participants), employees, or officers taken pursuant to or under color of this Agreement.

20.1.2 Participant Indemnity. Each Participant shall defend and indemnify the other Participants from and against any claim or liability, including any related loss or cost, caused by or resulting from the design, construction, installation, operation, or maintenance of any of the electric facilities owned, operated, or maintained by the indemnifying Participant or by reason of the acts or omissions of its agents, contractors, servants, or employees in connection therewith.

20.1.3 IMC Indemnity. To the fullest extent permitted by law, the IMC shall indemnify and hold its members, authorized agents, and officers harmless against all claims and liabilities which they or any of them incur as a party defendant to any proceeding, except one filed by or in the right of the IMC, based on any authorized action of any such person as a member of the IMC, an authorized agent of the IMC, or as an officer of the IMC within the scope of the member's office.

20.1.4 User Agreements. The IMC shall include provisions in any agreements with Users that provide equivalent indemnity rights and responsibilities for such Users as those provided for and required of Participants in this Article provided, however, that this Section may not apply to AEA or other state entities.

Section 20.2 Comparative Negligence

Any liability, including costs of defense and attorney fees, for claims arising from the concurrent negligence of two or more Participants and/or Users will be apportioned according to the respective percentage of fault attributable to each Participant and/or User as determined by agreement or by the trier of fact.

Article 21.
WARRANTY DENIAL AND EXCLUSIVITY OF CONTRACT

Section 21.1 AEA Denial of Warranty

AEA does not warrant the Intertie facilities it owns as fit for their intended use or the reliability or availability of the Intertie for intended operations covered by this Agreement.

Section 21.2 Exclusivity of Contract

The terms of this Agreement and any provisions adopted by reference or otherwise incorporated into this Agreement set forth the full intent and agreement of AEA and the Participants regarding the matters covered by this Agreement. However, this Agreement does not supersede related written agreements, such as the Intertie maintenance agreements between AEA and GVEA or AML&P, but is to be interpreted consistently with them.

Article 22.
UNCONTROLLABLE FORCES

Section 22.1 Limited Excuse of Performance.

A Participant will not be in default in performance of any obligation hereunder, other than the obligation to make payments as provided in this Agreement, if failure of performance is due to uncontrollable forces and without the fault or negligence of that Participant. Strikes, lockouts, and other labor disturbances are considered uncontrollable forces and nothing in this Agreement will require a Participant to settle a labor dispute against its better judgment.

Section 22.2 Suspension of Performance.

If a Participant, by reason of an uncontrollable force, is rendered unable, wholly or in part, to perform its obligations under this Agreement (other than its obligations to pay money), then upon that Participant giving notice and the particulars of the uncontrollable force, its obligation to perform will be suspended during the continuance of, but only to the extent of, any inability so caused, but for no longer period thereof, and the effects of such cause shall, so far as possible, be remedied with all reasonable dispatch; provided, however, that the settlement of labor disputes shall be considered wholly within the discretion of the Participant involved. The affected Participant will not be responsible for its delay in performance under this Agreement to the extent caused by an uncontrollable force, nor will such uncontrollable force give rise to claim for damages or constitute default.

Article 23.
WAIVERS

Any waiver at any time by a Participant or the IMC of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay short

of the statutory period of limitations in asserting or enforcing any right shall not be deemed a waiver of such right.

Article 24.
SUCCESSORS AND ASSIGNS; NO THIRD PARTY BENEFICIARIES

Section 24.1 Successors and Assigns

This Agreement shall be binding upon and inure to the benefit of the successors, legal representatives, or assigns of the respective Participants. However, no Participant shall assign this Agreement nor any part hereof without the express written consent of the IMC, which consent shall not be unreasonably withheld or delayed. Nor shall a Participant be relieved of its obligations hereunder by an assignment of less than all of the benefits and burdens hereunder or impose additional obligations or burdens on the other Participants by an assignment of this Agreement or any part hereof. The consent of the IMC under this section shall require at least the affirmative vote of a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA

Section 24.2 No Third-Party Beneficiaries

The provisions of this Agreement shall not create any rights in favor of any person, corporation, or association not a Participant in this Agreement, except as provided herein for Users, and the obligations herein assumed are solely for the use and benefit of the Participants to this Agreement.

Article 25.
GOVERNING LAW

This Agreement is made subject to, and shall be governed by and construed in accordance with, the laws of the State of Alaska and the authority granted to the individual Participants thereunder.

Article 26.
CAPTIONS, MERGER OF ADDENDA AND EXHIBITS

Section 26.1 Captions

Captions of the various articles herein are intended for convenience of reference only and shall not define or limit any terms or provisions.

Section 26.2 Merger

The following addendum and exhibits as attached hereto are hereby merged into this Agreement:

Exhibit A – Former AS 44.83.380
Exhibit B – Definitions

Exhibit C – Form of New Participant Addendum
Exhibit D – Former AS 44.83.398(f) Exhibit E – Intertie Facilities Diagram
Exhibit E – Intertie Facilities Diagram
Exhibit F – Form of User Agreement
Exhibit G - Sample MITCR Calculation
Exhibit H – Reserve Capacity and Operating Reserve Responsibility Agreement

Subsequent Entering Participant addenda also shall be merged into this Agreement upon their execution by AEA and the Participants.

Article 27.
NOTICES

Section 27.1 Notices

27.1.1 Address. Any notice or demand under this Agreement is properly given if sent by registered or certified mail and addressed to the following:

General Manager
Municipality of Anchorage, Alaska
Municipal Light and Power
1200 East First Avenue
Anchorage, Alaska 99501

Executive Director
Alaska Energy Authority
813 West Northern Lights Blvd.
Anchorage, Alaska 99503

President
Alaska Electric Generation
and Transmission Cooperative, Inc.
3977 Lake Street
Homer, Alaska 99603

Chief Executive Officer
Chugach Electric Association, Inc.
Pouch 6300
Anchorage, Alaska 99503 or
5601 Electron Drive
Anchorage, Alaska 99502

President and CEO
Golden Valley Electric Association, Inc.
P.O. Box 71249

Fairbanks, Alaska 99707 or
758 Illinois Street
Fairbanks, Alaska 99701

with a copy to:

Kirk H. Gibson
McDowell Rackner & Gibson PC
419 SW 11th Ave., Suite 400
Portland, Oregon 97205

The foregoing designations of the name or address to which notices or demands are to be directed may be changed at any time by written notice given by any Participant to all others.

27.1.2 Means of Notice. Any notice or request of a routine character in connection with the use of Capacity or delivery of Energy, or in connection with the operation of facilities, shall be given in the manner so designated by the Operating Committee, or the IMC.

Article 28.
AMENDMENTS

Except as expressly provided for in this Agreement, neither this Agreement nor any part hereof may be terminated, amended, supplemented, waived, or modified except by a written instrument signed by a minimum of 75 percent of the members of the IMC constituting greater than 66 percent of the total Annual System Demand of all members of the IMC, including the affirmative vote of AEA.

Article 29.
MUTUAL RIGHT OF ENTRY

Each Participant and AEA hereby grants a license and permit to the operators of the Intertie, including the operators' employees or contractors, to enter upon its rights-of-way and to make use of its easements (or similar right to use or enter upon property) to perform work related to the repair, operation or maintenance of Intertie facilities located thereon. Any such entry shall comply with the requirements and restrictions of the right-of-way or easement. Notice of entry and the purpose(s) for it shall be provided to the owner or holder in as timely a manner as is practicable under the then-existing circumstances.

Article 30.
AGENTS

Each Participant shall provide notice to the IMC and the operators of the Intertie of that Participant's appointment of an agent, or Designated Contractor. The Participant shall remain fully responsible under this Agreement for all acts or failures to act of its agents or Designated

Contractors. Appointment of an agent or Designated Contractor shall not relieve a Participant of any of its responsibilities or obligations under this Agreement. The appointment of an agent or Designated Contractor shall not be used to have, or have the right to control more than one vote or have more than one voting representative on the IMC. See Section 8.1, Establishment of the Intertie Management Committee, Right to Vote. An agent or Designated Contractor must meet the requirements of this Agreement to become a Participant.

Article 31.
AGREEMENT APPROVAL AND TRANSMITTAL

By signing this Agreement, a Participant does not subject itself to rate regulation by the Regulatory Commission of Alaska (RCA). AEA will transmit this Agreement to the RCA for informational purposes only.

[The remainder of this page intentionally left blank]

Article 32.
CONSTRUCTION OF AGREEMENT

Each Participant agrees that it has participated as fully as it deemed prudent in the drafting and negotiation of this Agreement. Accordingly, the Agreement will not be construed against any particular Participant, or Participants, as the drafter.

IN WITNESS WHEREOF, the Participants have caused this Agreement to be executed by their duly authorized officers or representatives as of the day and year first above written. This Agreement may be executed in counterparts each of which shall be an original, and all of which shall be merged into this Agreement.

ALASKA ENERGY AUTHORITY

By: Sam Fisher Gord

Title: Executive Director

SUBSCRIBED AND SWORN TO before me on the 18th day of Nov, 2011.

SHAUNA M. HOWELL NOTARY PUBLIC STATE OF ALASKA

Shauna M. Howell

Notary Public, State of Alaska

My Commission Expires: until office

MUNICIPALITY OF ANCHORAGE, ALASKA d.b.a. MUNICIPAL LIGHT AND POWER

By:

Title: Municipal Manager

SUBSCRIBED AND SWORN TO before me on the 18th day of Nov., 2011.

SHAUNA M. HOWELL NOTARY PUBLIC STATE OF ALASKA

Shauna M. Howell

Notary Public, State of Alaska

My Commission Expires: until office

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Bradley Evans

Title: CEO

SUBSCRIBED AND SWORN TO before me on the 18th day of Nov, 2011

Shauna M. Howell

Notary Public, State of Alaska

My Commission Expires: Until Office

SHAUNA M. HOWELL NOTARY PUBLIC STATE OF ALASKA

GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.

By:

Title: President / CEO

SUBSCRIBED AND SWORN TO before me on the 17th day of Nov., 2011.

Shauna M. Howell

Notary Public, State of Alaska

My Commission Expires: Until Office

SHAUNA M. HOWELL NOTARY PUBLIC STATE OF ALASKA

ALASKA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC.

By: _____

Title: General Manager

SUBSCRIBED AND SWORN TO before me on the 18th day of Nov., 2011.

_____

Notary Public, State of Alaska

My Commission Expires: with office

SHAUNA M. HOWELL NOTARY PUBLIC STATE OF ALASKA

EXHIBIT A
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

TEXT OF FORMER AS 44.83.380

EXHIBIT A
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

TEXT OF FORMER AS 44.83.380

c. 44. 83. 380. Program established

(a) The energy program for Alaska is established. The program shall be administered by the Alaska Power Authority.

(b) The energy program for Alaska is a program by which the authority may acquire or construct power projects with money appropriated by the legislature to the power development fund established in AS 44.83.382. A power project may be acquired or constructed as part of the energy program for Alaska only if the project is submitted to and approved by the legislature in accordance with procedures set out in AS 44.83.177 – 44.83.187.

(c) The provisions of AS 36.10.010 – 36.10.125 apply to power projects constructed by the authority under AS 44.83.380 – 44.83.425.

(Section 1, chapter 118 SLA, 1981)

EXHIBIT B
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

DEFINITIONS

EXHIBIT B
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

DEFINITIONS

ABBREVIATIONS

1.	AML&P	Municipal Light and Power, a department of the Municipality of Anchorage, Alaska.
2.	AEA	Alaska Energy Authority.
3.	AEG&T	Alaska Electric Generation and Transmission Cooperative, Inc., of which Homer Electric Association, Inc. and Matanuska Electric Association, Inc. are members.
4.	APA	Alaska Power Authority (predecessor agency to AEA).
5.	CEA	Chugach Electric Association, Inc.
6.	GVEA	Golden Valley Electric Association, Inc.
7.	HEA	Homer Electric Association, Inc.
8.	MEA	Matanuska Electric Association, Inc.

DEFINITIONS

1. **Accredited Capability of a Participant** – shall mean: (a) the net generating capability of a Participant; plus (b) the value in kilowatts assigned to that Participant's purchases and/or firm commitments for power from electric suppliers under contracts now existing or hereafter created; minus (c) the value in kilowatts assigned to any commitment of that Participant to deliver power to any electric supplier or suppliers pursuant to any valid order or under separate contract or contracts now existing or hereafter created. The Accredited Capability of a Participant may be determined and assigned by the Operating Committee in accordance with the provisions of the Agreement.

2. **Affiliate(s)** – shall mean any subsidiary or other entity which is associated with or has a legal relationship with a Party to the Agreement, or a successor agreement, or any related agreements. Such association shall be considered the ownership of a

controlling interest or other right to control, either directly or indirectly, the affairs of the affiliated entity.

3. **Agreement** – shall have the meaning as provided in the preamble of the Agreement.

4. **Annual Debt Service Cost** – shall have the meaning provided in Section 7.1.1.3.

5. **Annual System Demand** – shall mean the highest hourly System Demand occurring during the 12-month period ending with the current month and that is used in the MITCR calculations.

6. **Available Accredited Capability of a Participant.** – shall mean the Accredited Capability adjusted for generating capacity out of service for maintenance or repair.

7. **Capacity** – shall mean the time rate of generating, transferring or using electric Energy, usually expressed in kilowatts.

8. **Capacity Rate (or Intertie Capacity Rate)** – shall have the meaning provided in Section 7.2.6, Capacity Rate.

9. **Control Area** – shall mean an interconnected system of one or more utilities which manually or automatically controls all generation to meet the total load, plus or minus the power it is delivering or receiving from neighboring systems by exercising operating control of the resources necessary to meet the loads within the Control Area on an instantaneous and continuous basis. The Participant exercising operating control for a Control Area provides the following services:

a. regulate generating facilities and other power resources to effect instantaneous and continuous supply of the power requirements of the loads within the Control Area;

b. regulate generating facilities to assist in the control of frequency and time correction; and

c. monitor continuously the power flows between the Control Area and the Control Area(s) with which it is interconnected.

10. **Cost of Improvements** – shall have the meaning provided in Section 7.1.1.6.

11. **Declared Capability** – shall mean the current capability of a generating unit which is not greater than the published capability of the unit.

12. **Decremental Cost** – shall mean the cost of fuel, operating labor and maintenance which would have been incurred to provide the Operating Reserves at any time and which are avoided by the other Participant, including the cost of avoiding the starting and operating of a generating unit or units and a proportional amount of the annual debt service on the capital investment of the highest cost (per kw) generating unit

on the receiving Participant's system. The decremental cost of Operating Reserves shall be the total of such avoided costs to the receiving Participant. In situations where a Participant would have incurred replacement fuel costs which are higher than the cost of existing fuel supply, replacement costs shall be utilized.

13. **Designated Contractor** – shall mean the contractor designated by the United States Army from time to time as provided in Article 30, AGENTS, to operate the utility systems on the United States Army's bases.

14. **Effective Date** – shall have the meaning provided in the preamble of the Agreement.

15. **Emergency Outage (Forced Outage)** – shall mean any unanticipated, unscheduled outage of generating or transmission facilities for other reasons than planned maintenance. Such outage classification shall not exceed a period of four hours.

16. **Energy** – shall mean as commonly used in the electric utility industry, electric energy means kilowatt hours (kWh).

17. **Energy Rate** – shall have the meaning provided in Section 7.2.5, Energy Rate.

18. **Extraordinary Maintenance and Replacements Costs** – shall have the meaning provided in Section 7.1.1.2.

19. **GVEA Control Area** – shall have the meaning as provided in Section 10.1.3, GVEA Responsibilities.

20. **Improvement** – shall have the meaning provided in Section 6.4.1, Development of Improvements.

21. **IMC** – shall mean the Intertie Management Committee. The criteria for membership in the IMC is provided in Section 4.3, Membership In IMC, and its establishment, authority and duties are set out in Article 8, INTERTIE MANAGEMENT COMMITTEE.

22. **IMC Bylaws** – shall have the meaning provided in Section 8.2, Adoption of Procedural Rules or Bylaws.

23. **Incremental Cost** – shall mean the cost of fuel, operating labor, maintenance and a proportional amount of the annual debt service on the capital investment of the next generating unit that would be used to provide the required capability and Energy. It shall include the cost of starting and operating any generating unit required to provide such Energy. The incremental cost of supplying Operating Reserve shall be the total of such costs for the period of time involved. In situations where a Participant will incur replacement fuel costs which are higher than the cost of the existing fuel supply, replacement costs shall be used.

24. **Incremental Energy Cost** – shall mean the cost of fuel, operating labor and maintenance to generate the next unit of Energy required at any time, including the cost of starting and operating any generating unit which must be started as a result of

supplying such Energy. The incremental cost per kilowatt hour for any particular transaction shall be the total of such costs divided by the kilowatt hours scheduled for delivery to the receiving Participant. In situations where a Participant will incur replacement fuel costs which are higher than the cost of existing fuel supply, replacement costs shall be used.

25. **Interruptible Transmission Service** – shall mean a service providing for transmission of electric Energy in bulk from one utility system through the utility's transmission system providing the transmission service to another utility. This service is made available with the understanding that it can be curtailed or interrupted at any time with little or no notice at the discretion of the supplier.

26. **Intertie** – shall mean the electrical transmission facilities constructed by APA or AEA to interconnect the Participants in North-Central Alaska with the Participants in South-Central Alaska and facilities under contract to AEA that are part of the interconnected Intertie system.

27. **Intertie Costs** – shall have the meaning provided in Section 7.1, Intertie Costs.

28. **Intertie Point of Interconnection** – shall mean the AEA-owned facilities in the Douglas Substation, which is also the point of interconnection between AML&P's and GVEA's Control Areas.

29. **Intertie Operators** – shall mean the operators at the control centers of AML&P and GVEA, the utilities that have operational responsibility for the Intertie under Article 10, OPERATION OF THE INTERTIE.

30. **Intertie System** – shall mean the Participants of the Alaska Intertie Agreement functioning as an interconnected electrical system.

31. **Intertie Transaction** – shall mean transfer of electric energy on the Intertie or a commitment to provide reserve capacity between Participants and/or Users.

32. Intertie User **Agreement or User Agreement** - shall mean an agreement adopted by the IMC pursuant to the requirements of Section 8.6.2, Intertie User Agreements, which provides common terms and conditions for Capacity and Energy transactions on the Intertie by Participants and Users. The initial form of the User Agreement is Exhibit F to the Agreement

33. **Maximum Intertie Transfer Capability** – shall mean, for purposes of this Agreement, the maximum Intertie transfer capability is 78 MW, net of losses, as provided in Section 6.3, Maximum Intertie Transfer Capability, unless changed by the IMC pursuant to Section 6.2.4, IMC Authority to Change Capacity Allocation Methodology.

34. **MITCR** – shall mean the Minimum Intertie Transfer Capability Rights as discussed in Article 6, MINIMUM RIGHTS OF THE PARTICIPANTS AND USERS TO USE INTERTIE FACILITIES. A sample MITCR calculation is included at Exhibit G.

35. **New Participant Addendum** - shall mean the agreement required by Section 4.2, New Participant, as part of the requirements for the addition of a new Participant.

36. **Non-Spinning Reserve** – shall mean all unloaded generating capability not meeting the Spinning Reserve criteria that can be made fully effective in 45 minutes.

37. **Northern Group** – Shall initially mean GVEA.

38. **Open Access** – shall have the meaning provided in Section 16.1, Definition.

39. **Operating Committee** – shall mean the committee established by Section 9.1, Establishment of the Operating Committee.

40. **Operating Reserve** – shall mean the sum of Spinning and Non-Spinning Reserves.

41. **Operating Reserve Obligation** – shall mean that amount of Spinning Reserve and Non-Spinning Reserve which a Participant is obligated under the terms of this Agreement to provide for the purpose of maintaining continuity of service.

42. **Operation and Maintenance Costs** – shall have the meaning provided in Section 7.1.1.1.

43. **Original Agreement** – shall mean the Alaska Intertie Agreement dated December 23, 1985.

44. **Participant** – shall have the meaning provided in the preamble to the Agreement and Article 4, PARTICIPANT.

45. **Payment Obligation** – shall have the meaning provided in Section 8.7, Payment Obligation Unimpaired.

46. **Prudent Utility Practices** – shall mean Prudent Utility Practices at a particular time means 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 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 the Agreement, equitable consideration should be given to the circumstances, requirements and obligations of each of the Participants, and the fact that the Participants 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.

47. **Railbelt** – shall mean, in reference to a utility or Participant, those electrically connected electric utilities situated along the Alaska Railroad from Fairbanks to Seward, Alaska.

48. **Reliability Standards** – shall mean those standards having to do with promoting the reliable operation of the Intertie developed, adopted and enforced by the IMC in compliance with the requirements of Article 3, OPERATING AND RELIABILITY STANDARDS AND ENFORCEMENT. The Reserve Capacity and Operating Reserve Responsibility agreement, which is Exhibit H to the Agreement, will constitute the Reliability Standards until such time as the IMC adopts and implements additional standards.

49. **Reliability Standards Implementation Agreement** – shall mean that contractual agreement between the IMC and the Participants and Users for the implementation of IMC-approved reliability standards.

50. **Representative** – shall have the meaning provided in Section 9.1.2, Representatives.

51. **Required Work** – shall have the meaning as provided in Section 8.8, AEA's Ability to Perform Required Work, and Section 6.4.4, Right to Make Improvements – Required Work.

52. **Reserve Capacity** – shall mean the excess in kilowatts of a system's Net Generating Capability over its maximum System Demand for any period.

53. **Reserve Capacity Obligation** – shall mean the capacity which a Participant is obligated to reserve and use for the purpose of maintaining continuity of service.

54. **Reserve Fund** – shall mean the fund established to provide for repairs to and replacements of Intertie Facilities pursuant to Section 7.1.1.4, and Section 8.6.12, Creation of Reserve Fund, consistent with Prudent Utility Practice and in compliance with applicable law and regulations, or as required by any bond or other borrowing covenants.

55. **Scheduled Outage** – shall mean any outage of generating or transmission facilities which is scheduled in advance to be out of service.

56. **Southern Group** – shall initially mean AML&P, CEA, AEG&T, MEA, and HEA.

57. **Spinning Reserve** – shall mean the amount of unloaded generating capability of a Participant connected to and synchronized with the interconnected system of the Participants and ready to take load. Spinning Reserve allocation to any generator shall not exceed the amount of generation increase that can be realized immediately from normal governor control.

58. **System Demand** – shall mean 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 a system's consumers, including system losses, and also including any wheeling losses occurring on other systems and supplied for transmission of such Energy, but excluding generating station uses and excluding wheeling losses supplied by another system.

59. **Total Operating Reserve Obligation** – shall mean that amount of Spinning Reserve and Non-Spinning Reserve of the Participants collectively required to maintain continuity of service.

60. **Transmission Service** – shall mean service provided by the use of the transmission system of a Participant directly connected to the Intertie for wheeling of power and energy through its system for another Participant.

61. **Transmission Service Facilities** – shall mean the integrated transmission facilities of the transmitting utility, excluding power plant step-up transformation and radial lines to loads or generators.

62. **User** – shall mean any entity actually using the Intertie that has executed a User Agreement, including a Participant that has executed a User Agreement.

63. **User Agreement or Intertie User Agreement**– shall mean an agreement adopted by the IMC pursuant to the requirements of Section 8.6.2, Intertie User Agreement, that provides common terms and conditions for Capacity and Energy transaction on the intertie by Participants and Users. The initial form of the User Agreement is Exhibit F to the Agreement.

* * * * *

EXHIBIT C
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

NEW PARTICIPANT ADDENDUM

NEW PARTICIPANT ADDENDUM
TO THE
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

This New Participant Addendum to the Amended and Restated Alaska Intertie Agreement ("Addendum") is made by and between _____ ("New Participant"), and the Intertie Management Committee ("IMC") on _____, 20____ in order to comply with the terms and conditions for the admission of new Participants as set forth in the Amended and Restated Intertie Agreement dated November____, 2011, ("Intertie Agreement").

THEREFORE, in consideration of the mutual covenants in this Addendum, the New Participant and the IMC agree as follows:

Article 1.
DEFINITIONS

Except as specifically set forth in this Addendum, definitions for capitalized terms are as specified in Exhibit B to the Intertie Agreement and are incorporated herein by this reference. Exhibit B to the Intertie Agreement may be amended from time to time in the manner provided in Article 28, AMENDMENTS, of the Intertie Agreement.

Article 2.
TERM AND EFFECTIVE DATE

Section 2.1 Effective Date of the Addendum

This Addendum shall be effective and the New Participant shall be a Participant with the same rights and obligations as the other Participants under the Intertie Agreement upon the date of last to occur of: a) the execution of this Addendum by the IMC; b) the IMC's determination pursuant to Section 4.2, New Participant of the Intertie Agreement, if required, or, if applicable, the New Participant's compliance with Article 5, WITHDRAWAL OF AEG&T AND OTHER PARTICIPANT AND USER STATUS of the Intertie Agreement ("Effective Date").

Article 3.
COMPLIANCE WITH INTERTIE AGREEMENT AND STANDARDS

Section 3.1 Compliance With Intertie Agreement, Operating and Reliability Standards

3.1.1 Compliance With Intertie Agreement. The New Participant agrees to comply with the provisions of the Intertie Agreement and to fully and faithfully perform the duties and responsibilities of a Participant as provided in the Intertie Agreement in the same manner and effect as if New Participant was a signatory to the Intertie Agreement. New Participant hereby acknowledges

that it has received a current copy of the Intertie Agreement and that it is aware that the Intertie Agreement may be amended from time to time.

3.1.2 Compliance With Standards. Upon and after the Effective Date of this Addendum, the New Participant agrees to execute any necessary agreements and take such reasonable actions as may be required by the IMC in order to implement any operating standards or Reliability Standards approved by the IMC. The New Participant agrees to comply with any operating standards and Reliability Standards in force on the effective date of this Addendum or subsequently adopted by the IMC and, in the event of failure to comply, agrees to be subject to any sanctions applicable to such failure, all as provided in the Intertie Agreement.

3.1.3 Required Data Submissions. Upon and after the Effective Date of this Addendum, the New Participant or its designated agent or Designated Contractor shall submit all data as reasonably requested by the IMC, whether related to any operating standards, Reliability Standards, or otherwise. The New Participant shall notify the IMC of its designation of an agent or Designated Contractor prior to having that agent or Designated Contractor submit any data on behalf of the New Participant.

Article 4.
NOTICES

Any notice or demand under this Agreement is properly given if sent by registered or certified mail and addressed to the following:

New Participant:

_____
_____
_____
_____
_____

with a copy to:

_____
_____
_____
_____

IMC:

_____
_____
_____
_____
_____

with a copy to:

Kirk H. Gibson
McDowell Rackner & Gibson PC
419 SW 11th Avenue, Suite 400
Portland, OR 97205

Article 5.
WAIVERS

Any waiver at any time by the New Participant or the IMC of its rights with respect to a default under this Addendum, or with respect to any other matter arising in connection with this Addendum, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not be deemed a waiver of such right.

Article 6.
SUCCESSORS AND ASSIGNS; NO THIRD PARTY BENEFICIARIES

Section 6.1 Successors in Interest

No signatory hereto may assign this Addendum or any part hereof for any reason and any attempt to do so shall be void.

Section 6.2 No Third-Party Beneficiaries

The provisions of this Addendum shall not create any rights in favor of any person, corporation, or association not a signatory to this Addendum or the Intertie Agreement, and the obligations herein assumed are solely for the use and benefit of the signatories to this Addendum and the Agreement.

Article 7.
GOVERNING LAW

This Addendum is made subject to, and shall be governed by and construed in accordance with, the laws of the State of Alaska and the authority granted to the individual Participants thereunder.

Article 8.
CAPTIONS

Captions of the various articles herein are intended for convenience of reference only and shall not define or limit any terms or provisions.

Article 9.
AMENDMENTS

Neither this Addendum nor any part hereof may be terminated, amended, supplemented, waived, or modified except by an instrument in writing signed by the IMC, and the New Participant.

Article 10.
CONSTRUCTION OF AGREEMENT

Each signatory to this Addendum agrees that it has had its legal advisers review this Addendum. Accordingly, the Addendum will not be construed against any particular party as the drafter.

IN WITNESS WHEREOF, the IMC, and New Participant have caused this Addendum to be executed by their duly authorized officers or representatives as of the day and year first above written.

NEW PARTICIPANT

By:_____

Title:_____

SUBSCRIBED AND SWORN TO before me on the _____ day of _____, 2011.

_____
Notary Public, State of Alaska
My Commission Expires: _____

INTERTIE MANAGEMENT COMMITTEE

By:_____

Title:_____

SUBSCRIBED AND SWORN TO before me on the _____ day of _____, 2011.

_____
Notary Public, State of Alaska
My Commission Expires: _____

EXHIBIT D
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

TEXT OF FORMER AS 44.83.398(f)

EXHIBIT D
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

TEXT OF FORMER AS 44.83.398(f)

(f) The provisions of (b) of this section do not apply to an intertie that is authorized as a separate project under former AS 44.83.380. The authority shall establish and maintain separate power rate schedules applicable to each intertie that has acquired or constructed as a separate power project under the energy program for Alaska. The power rate schedules shall produce sufficient revenue from utilities connected by the intertie to pay (1) operation, maintenance, and equipment replacement costs of the intertie; (2) debt service of the intertie; and (3) safety inspections investigations of the intertie by the authority.

If the authority determines that intertie has ceased to function as a separate project and has become a part of one or more other power projects as a transmission line, the power rate schedules established under this subsection shall be terminated and a wholesale power rate applicable to the former intertie shall be calculated under (b) of this section for the project or projects of which it has become a part.

EXHIBIT E
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

INTERTIE FACILITIES DIAGRAM

EXHIBIT E

AMENDED AND RESTATED ALASKA INTERTIE AGREEMENT

INTERTIE FACILITIES DIAGRAM

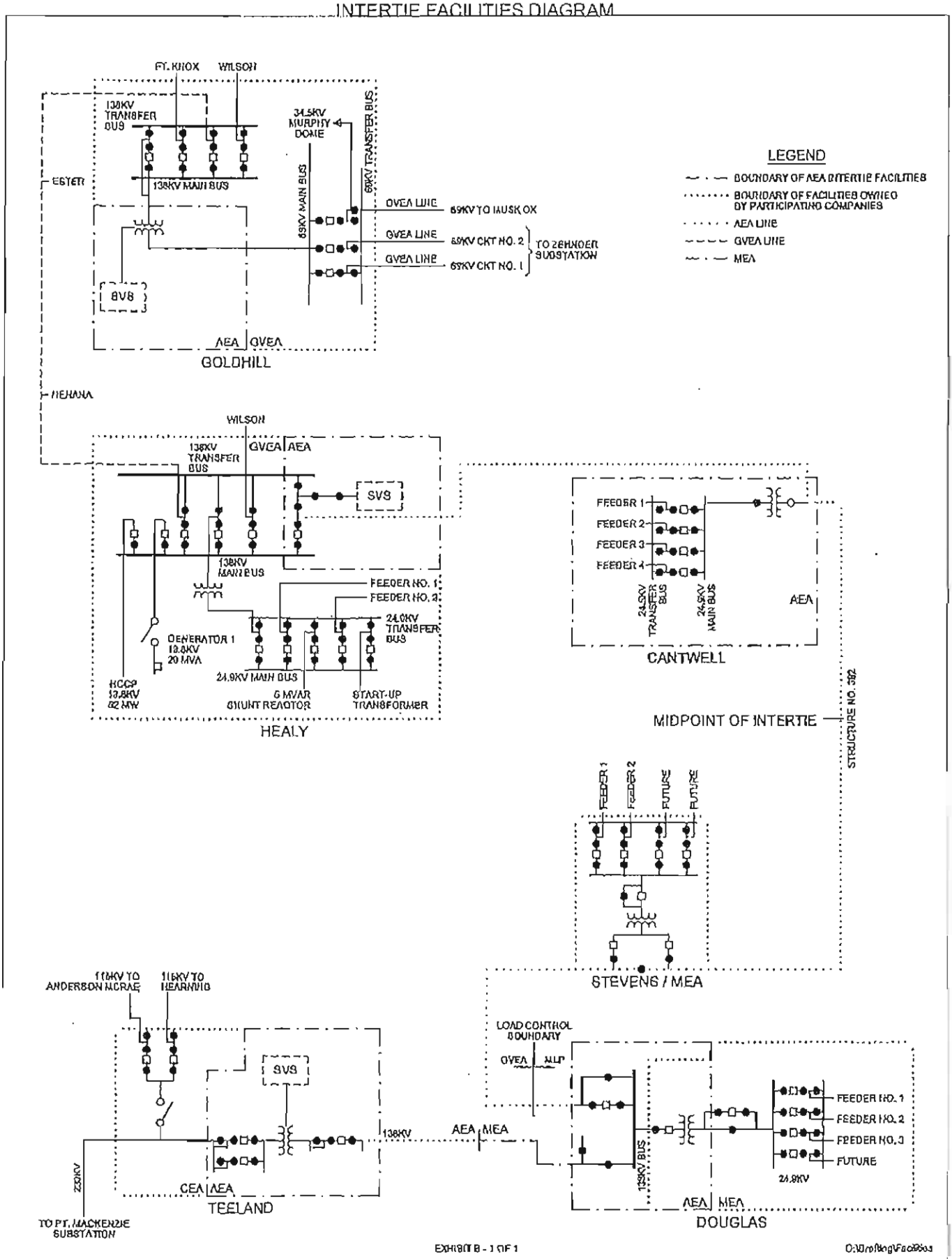

EXHIBIT F
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

FORM OF USER AGREEMENT

EXHIBIT F
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

FORM OF USER AGREEMENT

This Intertie User Agreement ("User Agreement"), is made and entered into this ____ day of _____, 20__, between the Intertie Management Committee, ("IMC"); and, _____ ("User") to set forth the basic terms and conditions of User's right to use the Alaska Intertie ("Intertie"). The rights and responsibilities of all Intertie users, as well as the manner and means of operating the Intertie, are as set forth in the Amended and Restated Alaska Intertie Agreement ("Intertie Agreement") which is attached as Exhibit 1. The IMC and User shall be referred to individually as "Party" and collectively as "Parties."

The Parties hereby agree:

1. TERM, TERMINATION, AND CONSTRUCTION.

1.1 Term.

This User Agreement shall become effective upon its execution by the Parties and shall expire on the earlier of: (a) its termination as set forth in Section 1.2, Termination, of this User Agreement; (b) the expiration of the power supply contract User has with an AEA project; or (c) at 24:00 hours Alaska Standard Time on _____.

1.2 Termination.

This User Agreement may be terminated by:

a. The mutual agreement of both Parties for termination evidenced by a writing executed by the authorized representatives of both Parties.

b. Either Party, upon thirty (30) days written notice.

c. The IMC for cause, in the event of User's material breach of this User Agreement.

d. The IMC for Cause, if User's non-compliance with the Intertie operating policies and procedures or Reliability Standards results in or contributes to sanctions against another party, and User has not reimbursed such other party

for the full cost of any such non-compliance or sanctions within thirty (30) days of notice from the IMC.

e. The IMC For Cause, upon User's failure to timely pay any Intertie related charge, cost, or sanction that is due and owing within thirty (30) days notice of such failure from the IMC.

1.3 Construction

Unless specifically provided otherwise in this User Agreement, all capitalized terms shall have the meanings set out in Exhibit B of the Intertie Agreement.

2. COMPLIANCE WITH IMC REQUIREMENTS.

The User shall comply with the requirements of all scheduling and other operating policies and procedures and any Reliability Standards established by the IMC and the Agreement. The User may be required to supply reserves and/or execute an agreement evidencing the User's obligation to supply reserves. In the event of failure to comply with any requirements of the IMC, User agrees to be subject to any sanctions applicable to such failure. User shall be entitled to all of the rights and privileges and be subject to all of the obligations of a Participant or User, as applicable, under the Intertie Agreement. The failure of the User to comply with the requirements of this section shall provide the IMC the right to terminate this User Agreement under Section 1.2(c), Termination.

3. RATES AND CHARGES

The rates and charges for use of the Intertie, including for any ancillary services, shall be as established by the IMC from time to time pursuant to the requirements of the Intertie Agreement.

4. ANCILLARY SERVICES AND RESERVES.

The User shall accept, and pay the IMC-approved charges for, any ancillary services required by the IMC related to User's use of the Intertie. The IMC at any time during the term of this agreement may require the User to execute an agreement to provide reserves to support its use of the Intertie. The failure of the User to comply with the requirements of this section shall provide the IMC with the right to terminate this User Agreement under Section 1.2(c), Termination.

5. PATH AND CAPACITY ALLOCATION.

The User shall have the right to use the Intertie at the points of receipt and delivery specified in Exhibit B to this User Agreement. Any additional, or required, facilities shall be as specified in the Intertie operating policies and procedures, Reliability Standards, or other requirements adopted by the IMC pursuant to the Intertie Agreement. Exhibit B shall also set out the amount of User's Intertie capacity allocation.

6. INTERTIE OPERATORS RIGHTS.

Nothing in this User Agreement shall affect the rights and obligations of the Intertie Operators to maintain the reliability of the Intertie, including disconnection or curtailment of service to the User. User shall cooperate with the Intertie Operators at all times.

7. CREDIT SUPPORT.

The User shall be subject to any credit support requirements adopted by the IMC to secure User's obligations under this User Agreement. Such credit support requirements may include providing a letter of credit, posting a bond, or other reasonable credit review procedures in accordance with standard commercial practices. The IMC may periodically review User's creditworthiness and increase, reduce, or eliminate the required support or payment security. User shall have the right to request such a review no more than twice each calendar year.

8. PROHIBITION ON ASSIGNMENT

This User Agreement may not be assigned by either Party without the consent of the other Party, which consent shall not be unreasonably withheld or delayed. Notwithstanding the foregoing, each Party shall have the right to assign its rights under this User Agreement for security purposes to a lender or guarantor in connection with loans to that Party. This right of assignment is subject to the following: (a) neither a secured lender nor guarantor exercising any rights, power or privileges with respect to this User Agreement under any mortgage, deed of trust or other security instrument shall be entitled to exercise the rights of the Party under this User Agreement unless the obligations of such Party hereunder shall have been performed; (b) an assignment shall not in any way relieve such Party of any obligations hereunder; and, (c) an assignment shall not be permitted hereunder if such assignment would adversely affect the tax exemption of interest on any Intertie bonds or financing that was issued on a tax-exempt basis.

9. TRANSFER OF CONTROL OR SALE OF GENERATION FACILITIES.

In any sale or transfer of control of any generation facilities owned or controlled by User for any Intertie Transactions subject to this User Agreement, User shall as a condition of such sale or transfer require the acquiring party or transferee, with respect to the transferred facilities, either to assume the obligations of the User with respect to this User Agreement or to enter into an agreement with the IMC imposing on the acquiring party or transferee the same obligations applicable to User pursuant to this User Agreement.

10. AMENDMENT

No amendment to this User Agreement shall be valid unless it is in writing and signed by both Parties hereto. The terms and conditions to this User Agreement shall remain in effect throughout the term and shall not be subject to change through application to a regulatory or other governmental body or authority by one Party absent the written agreement of the other Party.

11. NOTICES

Any notice, demand or request required or authorized by this User Agreement to be given in writing to a Party shall be delivered by hand, courier or overnight delivery service, mailed by certified mail (return receipt requested) postage prepaid, faxed, or delivered by mutually agreed electronic means and followed in writing to such Party at the following address:

User:

_____

_____

_____

_____

Email:

Fax:

IMC:

_____

_____

_____

_____

Email:

Fax:

The designation of such person and/or address may be changed at any time by either Party upon written notice to the other. Notice served by mail shall be effective upon receipt. Notice transmitted by electronic means (such as facsimile or, email) shall be effective upon receipt if received prior to 5:00 p.m. on any week day, and if not received prior to 5:00 p.m. on a week day, receipt shall be effective on the next week day, or as otherwise agree in writing by the Parties, so long as the notice transmitted by electronic means is followed in writing as set forth in this Article 11.

12. WAIVERS

Any waiver at any time by a Participant or the IMC of its rights with respect to a default under this Agreement, or with respect to any other matter arising in connection with this Agreement, shall not be deemed a waiver with respect to any subsequent default or matter. Any delay short of the statutory period of limitations in asserting or enforcing any right shall not be deemed a waiver of such right.

13. INTERPRETATION

Interpretation and performance of this User Agreement shall be in accordance with, and shall be controlled by, the laws of the State of Alaska. Article and section headings are for

convenience only and shall not affect the interpretation of this User Agreement. References to articles, sections and appendices are, unless the context otherwise requires, references to articles, sections and appendices of this User Agreement.

14. INDEMNITY

14.1 Responsibility for Indemnity

a. Costs of Indemnity. Each Party shall be responsible for the costs and liability arising out of, or in any way connected with, the acts or omissions of the Party, its agents, employees, or officers taken pursuant to or under color of this User Agreement.

b. Indemnity. Each Party shall defend and indemnify the other from and against any claim or liability, including any related loss or cost, caused by or resulting from the design, construction, installation, operation, or maintenance of any of the electric facilities owned, operated, or maintained by the indemnifying party or by reason of the acts or omissions of its agents, contractors, servants, or employees in connection therewith.

14.2 Comparative Negligence

Any liability, including costs of defense and attorney fees, for claims arising from the concurrent negligence of the Parties will be apportioned according to the respective percentage of fault attributable to each as determined by agreement or by the trier of fact.

15. SEVERABILITY

If one or more provisions herein shall be determined by a court of competent jurisdiction to be invalid, illegal or unenforceable in any respect, it shall be given effect to the extent permitted by applicable law, and such invalidity, illegality or unenforceability shall not affect the validity of the other provisions of this User Agreement.

16. COUNTERPARTS

This User Agreement may be executed in counterparts and each shall be merged and have the same force and effect as an original.

IN WITNESS WHEREOF, the IMC and the User have each caused this Intertie User Agreement to be executed by their duly authorized representatives as of the date first above written.

USER

By:_____

Its:_____

INTERTIE MANAGEMENT COMMITTEE

By:_____

Its:_____

EXHIBIT A

TO

FORM OF USER AGREEMENT

Copy of

AMENDED AND RESTATED ALASKA INTERTIE AGREEMENT

EXHIBIT B

TO

FORM OF USER AGREEMENT

DELIVERY/RECEIPT POINTS AND CAPACITY ALLOCATION

EXHIBIT B

TO

INTERTIE USER AGREEMENT

DELIVERY/RECEIPT POINTS:

CAPACITY ALLOCATION:

EXHIBIT G
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

SAMPLE MITCR CALCULATION

MINIMUM INTERTIE TRANSFER CABABILITY RIGHTS
(MITCR DETERMINATION)
FOR FISCAL YEAR 2012

Annual System Demand

	08 09	09 10	10 11	3 YR AVG.	
SOUTHERN PARTICIPANTS (MW)					
AML&P	186.0	175.0	177.0	179.3	MW
CEA	258.4	233.3	242.2	244.6	MW
MEA	144.2	132.0	137.2	137.8	MW
ARMY S	0.0	0.0	10.0	3.3	MW
TOTAL				585.0	MW
NORTHERN PARTICIPANTS (MW)					
ARMY N	0.0	0.0	22.0	7.3	MW
GVEA	223.1	220.5	211.5	218.4	MW
TOTAL				225.7	MW

MITCR DETERMINATION

		FY 12	
MEA	24.39%	19.02	MW
ML&P	31.73%	24.75	MW
CEA	43.29%	33.77	MW
ARMY S	0.58%	0.45	MW
ARMY N	3.20%	2.50	MW
GVEA	96.80%	75.50	MW
		155.99	MW
Interfie Capability N		78.00	
Interfie Capability S		78.00	

EXHIBIT H
TO
AMENDED AND RESTATED
ALASKA INTERTIE AGREEMENT

RESERVE CAPACITY
AND
OPERATING RESERVE RESPONSIBILITY AGREEMENT

EXHIBIT H

AMENDED AND RESTATED ALASKA INTERTIE AGREEMENT

RESERVE CAPACITY AND OPERATING RESERVE RESPONSIBILITY AGREEMENT

This Addendum No. 1 is made this 23rd day of December 1985, ~~1984,~~ by the Utility Participants, THE MUNICIPALITY OF ANCHORAGE, ALASKA, d.b.a. MUNICIPAL LIGHT & POWER; CHUGACH ELECTRIC ASSOCIATION, INC.; THE CITY OF FAIRBANKS, ALASKA, MUNICIPAL UTILITIES SYSTEM; GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.; and ALASKA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC., signatories to the Alaska Intertie Agreement, dated December 23, 1985, hereinafter referred to as "Agreement". The signatory parties are hereinafter referred to as "Utility Participants".

WITNESSETH

WHEREAS THE MUNICIPALITY OF ANCHORAGE, ALASKA, d.b.a. MUNICIPAL LIGHT & POWER; CHUGACH ELECTRIC ASSOCIATION, INC.; THE CITY OF FAIRBANKS, ALASKA, MUNICIPAL UTILITIES SYSTEM; GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.; and ALASKA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC. are all Utility Participants and signatories to the Alaska Intertie Agreement; and

WHEREAS the ALASKA POWER AUTHORITY is a Participant and signatory to the Alaska Intertie Agreement; and

WHEREAS the signatories to the Alaska Intertie Agreement desire to have a separate agreement involving only Utility Participants with reserve requirement responsibility on the interconnected system;

NOW THEREFORE, the Utility Participants agree as follows:

ARTICLE A
Reserve Capacity

Section A-1.1

A-1.1.1 Each Utility Participant expects and is expected to maintain utility responsibility for its own load and, as a part of such responsibility, shall maintain or otherwise provide for annually, Accredited Capability in an amount equal to or greater than its maximum System Demand for such year plus such Utility Participant's Reserve Capacity Obligation, as set forth in Subsection A-1.1.2 of this Section.

A-1.1.2 The Reserve Capacity Obligation of a Utility Participant, for any year, shall initially be

equal to thirty (30) percent of the projected Annual System Demand of that Utility Participant. The Reserve Capacity Obligation of the Participants may be adjusted from time to time by the Operating Committee.

A-1.1.3 The Operating Committee may determine the annual Accredited Capability for each Utility Participant.

ARTICLE B
Responsibility for Operating Reserve

Section B-2.1 Operating Reserve

B-2.1.1 Each Utility Participant shall provide Spinning Reserve and Non-Spinning Reserve as required by Section B-2.2 of this Article equal to or greater than the Operating Reserve Obligation of the Participant. As soon as practicable, but not to exceed four hours, after the occurrence of an incident which uses Operating Reserves, each Utility Participant shall restore its Operating Reserve Obligation by the procedures determined by the Operating Committee.

B-2.1.2 The Operating Reserves, Operating Reserve Obligation and Utility Participant's Allocation may be modified or adjusted from time to time by the Operating Committee.

Section B-2.2 Total Operating Reserve Obligation

B-2.2.1 The Total Operating Reserve Obligation at any time shall initially be an amount equal to 150 percent of the capability of the largest generating unit contingency in operation on the interconnected systems of the Utility Participants.

B-2.2.1.1 The Spinning Reserve portion of the total Intertie System shall not be less than an amount equivalent to 100 percent of the Declared Capability of the largest generating unit contingency in operation on the interconnected systems of the Utility Participants. The Declared Capability will be as determined by the Utility Participant.

B-2.2.1.2 The balance of the Total Operating Reserve Obligation shall be maintained with Non-Spinning Reserve.

B-2.2.2 Generating unit capability for Operating Reserves shall be determined by the following criteria:

a. It shall not be less than the load on the machine at any particular time nor greater than (b) below.

b. It shall not exceed that maximum amount of load (MW) that the unit is capable of continuously supplying for a two-hour period, or immediately supplying through action of automatic governor controls.

B-2.2.3 The criteria specified in this section may be modified or changed by the Operating Committee.

Section B-2.3 Utility Participant's Allocation of Operating Reserves

B-2.3.1 The Operating Reserve Obligation of a Utility Participant shall be that percentage of the Total Operating Reserve Obligation determined by the Operating Committee in accordance with the following formula based on the capability of largest generating unit contingency in operation at each Utility Participant.

B-2.3.1.1 Individual Utility Participant Reserve Allocation Formula

IOR = TOR x Us/Ut

IOR = Individual Utility Participant Operating Reserve Requirement

TOR = Total Operating Reserve Requirement

Us = A Utility Participant largest on-line generation unit capability

Ut = Sum of each Utility Participant's Us

Section B-2.4 Operating Reserve Calculation

B-2.4.1 System Spinning Reserve shall be calculated at any given instant as the difference between the sum of the net capability of all generating units on line in the respective system and the integrated Systems Demand of the system involved.

B-2.4.2 A Utility Participant's Spinning Reserve may be satisfied by an automatically controlled load shedding program. The load shedding program shall assure that controlled load can be dropped to meet the requirements of Spinning Reserve and in such a manner as to maintain system stability and not cause objectionable system conditions or cascading effects in other Utility Participants' systems. The Operating Committee shall review and approve the Utility Participant's load shedding program that will be used to satisfy its Spinning Reserve requirements.

B-2.4.3 The Operating Committee may establish procedures to assure that the Operating Reserve is available on the systems of the Participants at all times. Whenever a Participant is unable to meet its Operating Reserve Obligation, that Utility Participant will immediately, within two hours, advise all other Utility Participants and make arrangements to restore its Operating Reserve Obligation.

B-2.4.4 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.

B-2.4.5 A Participant may arrange for one or more other Utility Participants to supply part or all of its Operating Reserve requirement.

B-2.4.6 In an emergency, any Utility Participant, upon request by another Utility Participant, shall supply to such requesting Utility Participant part or all of its Operating Reserve up to the full amount of its Available Accredited Capability. A Utility Participant experiencing an emergency is not required to maintain its Operating Reserve Obligation. There shall be no obligation of a Utility Participant to supply Operating Reserve if the requesting Utility Participant is not making full use of its Available Accredited Capability.

B-2.4.7 Except as otherwise agreed, a Utility Participant supplying a portion or all of another Utility Participant's Operating Reserve during any month shall be paid by the purchasing Utility Participant an amount equal to whichever is greater of the following:

B-2.4.7.1 110 percent of the Incremental Cost of supplying such service; or

B-2.4.7.2 The Incremental Cost of supplying such service plus one-half of the overall savings involved in such transaction, which overall savings shall be equal to the difference between the Incremental Cost of the selling Utility Participant and the Decremental Cost of the purchasing Utility Participant.

B-2.4.8 If a Utility Participant fails to provide adequate Operating Reserve, other than because of a forced outage, during any such period the deficient Participant shall pay to the other Utility Participants an amount equivalent to two times the cost avoided by the deficient Utility Participant for not starting and/or operating any generating unit or units which would ordinarily be used to provide adequate Operating Reserve. Should the Utility Participant not have adequate Accredited Capability to provide the Operating Reserves, it shall pay the other Utility Participants two times the cost for starting and operating the highest cost generating unit on the deficient Utility Participant's system. This payment shall be shared by the other Utility Participants in the same proportion that their individual Annual System Demand is to the non-deficient Utility Participants' total Annual System Demand. Payments under this section B-2.4.8 of this Article B shall be waived for the first year of operation of the Intertie.

IN WITNESS WHEREOF, the Utility Participants have executed this Addendum No. 1 to the Alaska Intertie Agreement in quintuplet by their authorized officers or representatives as of the day and year first above written.

MUNICIPALITY OF ANCHORAGE, ALASKA dba MUNICIPAL LIGHT & POWER

By: Bob Smith

Municipal Manager
(Title)

SUBSCRIBED AND SWORN TO before me on the 23rd day of December, 1985.

Barbara Dunn
Notary Public, State of Alaska
My Commission Expires: 4-11-89

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Robert Martin Jr.

General Manager

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Susan Christianson
Notary Public, State of Alaska
My Commission Expires: 11-8-88

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Joyce M Mighy

President of the Board

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Susan Christianson
Notary Public, State of Alaska
My Commission Expires: 11-8-85

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Joseph M. Tessmann

Vice-President of the Board

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Susan Christianson
Notary Public, State of Alaska
My Commission Expires: 11-8-88

CITY OF FAIRBANKS, ALASKA
MUNICIPAL UTILITIES SYSTEM

By: [signature]

CITY MANAGER
(Title)

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Judith C. Hanover
Notary Public, State of Alaska
My Commission Expires: 10-17-87

GOLDEN VALLEY ELECTRIC
ASSOCIATION, INC.

By: [signature]

Gen. Mgr.
(Title)

SUBSCRIBED AND SWORN TO before me on the 16th day of December, 1985.

Kristi J. Smith
Notary Public, State of Alaska
My Commission Expires: January 11, 1987

ALASKA ELECTRIC GENERATION and
TRANSMISSION COOPERATIVE, INC.

By: [illegible]

President
(Title)

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

[illegible]
Notary Public, State of Alaska
My Commission Expires: 8/21/88

Letter from Intertie Management Committee
to Regulatory Commission of Alaska
Dated January 27, 2014
Subject: The Alaska Intertie – Railbelt
Operating and Reliability Standards

Exhibit 3

IMC Resolution 13-3, dated November 1, 2013

INTERTIE MANAGEMENT COMMITTEE

Resolution No. 13-3

WHEREAS, Article 3 and Article 9 of the Alaska Intertie Agreement, dated December 23, 1985 (1985 Agreement), provided that the Intertie Operating Committee (IOC) would be responsible for operating the interconnected Railbelt system and for developing operating procedures and standards practices with respect to such operations. The Intertie Management Committee (IMC) has assumed these responsibilities under the Amended and Restated Alaska Intertie Agreement, dated November 18, 2011 (2011 Amended Agreement). Further, that through Addendum No. 1 to the 1985 Agreement entitled "Reserve Capacity and Operating Reserve Responsibility" (incorporated as Exhibit H of the 2011 Amended Agreement) the Utility Participants of that agreement would be responsible for reserve requirements for the interconnected system; and

WHEREAS, the IMC (and previously the IOC) has been the de-facto Railbelt reliability coordinator for the Railbelt interconnection for over 25 years; and

WHEREAS, the IMC (and previously the IOC) has been the asset manager and operator of the Alaska Intertie Assets for over 25 years; and

WHEREAS, Section 3.1 of the 2011 Amended Agreement provides that the IMC shall determine Reserve Capacity and Operating Reserves for the Intertie, and the IMC has the authority to adopt operating policies and procedures, reliability standards, and enforcement mechanisms, for the Intertie; and

WHEREAS, on July 9, 2013, the IMC passed Resolution No. 13-1 without the affirmative vote of the Alaska Energy Authority (AEA) and passed Resolution No. 13-2 with the affirmative vote of the AEA, each Resolution regarding the "Intertie Management Committee's Railbelt Operating and Reliability Standards, updated June 7, 2013" ("June 7, 2013 Standards"); and

WHEREAS, IMC passage of Resolution 13-1 without the affirmative vote of AEA adopted the June 7, 2013 Standards as the operating policies and procedures for the Alaska Intertie assets, but did not adopt the Reliability Standards and enforcement processes for the Alaska Intertie assets;

WHEREAS, IMC passage of Resolution 13-1 without the affirmative vote of AEA adopted the June 7, 2013 Standards as the operating policies and procedures, Reliability Standards, and enforcement processes for the Railbelt interconnected system, exclusive of the Alaska Intertie assets; and

WHEREAS, IMC passage of Resolution 13-2 with the affirmative vote of AEA accepted the June 7, 2013 Standards, as the Reserve Capacity and Operating Reserves for the Intertie, Exhibit H of the 2011 Amended Agreement, and accepted as the operating policies and procedures, reliability standards, and enforcement mechanisms, for the Intertie, with two modifications. Resolution 13-2 incorporates a July 9, 2014 sunset and a requirement that the "sanctions" portions of the enforcement mechanisms in the document shall not become effective until separately approved by the IMC; and

WHEREAS, the IMC believes that the Reliability Standards and enforcement processes, including sanctions and other remedies that are the subject of Resolution 13-1 and 13-2, are a critical component of the conditions of joint use and interconnection of electric utilities in the Railbelt; and

WHEREAS, the IMC further believes that the public convenience and necessity would be served by formal adoption of these standards for the interconnected electric utilities of the Railbelt; and

WHEREAS, the IMC further believes that the Regulatory Commission of Alaska (RCA) may, under AS 42.05.141, "...do all things necessary or proper to carry out the purposes and exercise the powers expressly granted or reasonably implied in ..." AS 42.05; and

WHEREAS, the IMC further believes that the Regulatory Commission of Alaska (RCA) has authority under AS 42.05.321 to resolve disputes between interconnecting utilities regarding the conditions of joint use and interconnection of those utilities and further to determine the terms, conditions and compensation for that interconnection;

NOW, THEREFORE,

BE IT RESOLVED THAT the IMC repeals Resolutions 13-1 and 13-2.

BE IT FURTHER RESOLVED that the IMC adopts the "Intertie Management Committee's Railbelt Operating and Reliability Standards, updated October 1, 2013," as the Reserve Capacity and Operating Reserves for the Intertie, Exhibit H of the 2011 Amended Agreement, and as the operating policies and procedures, reliability standards, and enforcement mechanisms, with one modification made at the request of the Alaska Energy Authority respecting the Alaska Intertie assets and 2011 Amended Agreement:

> The "sanctions" portions of the enforcement mechanisms in the "Intertie Management Committee's Railbelt Operating and Reliability Standards, updated October 1, 2013," shall not become effective for purposes respecting the Alaska Intertie assets and 2011 Amended Agreement until separately approved by the IMC.

BE IT FURTHER RESOLVED that the Utility Participants of the IMC adopt the "sanctions" portions of the enforcement mechanisms in the "Intertie Management Committee's Railbelt Operating and Reliability Standards, updated October 1, 2013," for purposes respecting the interconnected Railbelt electric utilities, excluding the Alaska Intertie assets and 2011 Amended Agreement; and

BE IT FURTHER RESOLVED THAT this Resolution and the "Intertie Management Committee's Railbelt Operating and Reliability Standards, updated October 1, 2013" shall be submitted as an informational filing to the Regulatory Commission of Alaska (RCA).

BE IT FURTHER RESOLVED that the IMC shall request that the RCA exercise the authority granted to it under AS 42.05.321 and other applicable authority and to enter an order

1. Finding that the approval of these standards will serve the public convenience and necessity;
2. Formally approving the standards and finding that they are just and reasonable; and
3. Providing for mechanisms and processes for periodic review of the standards.

Bradley Evans, Chairman

Gene Therriault, Secretary

Letter from Intertie Management Committee
to Regulatory Commission of Alaska
Dated January 27, 2014
Subject: The Alaska Intertie – Railbelt
Operating and Reliability Standards

Exhibit 4

Addendum No. 1 to the Alaska Intertie Agreement, Reserve Capacity and Operating Reserve Responsibility

ADDENDUM NO. 1
TO THE
ALASKA INTERTIE AGREEMENT
RESERVE CAPACITY AND OPERATING RESERVE RESPONSIBILITY

This Addendum No. 1 is made this 23rd day of December 1985, ~~1984,~~ by the Utility Participants, THE MUNICIPALITY OF ANCHORAGE, ALASKA, d.b.a. MUNICIPAL LIGHT & POWER; CHUGACH ELECTRIC ASSOCIATION, INC.; THE CITY OF FAIRBANKS, ALASKA, MUNICIPAL UTILITIES SYSTEM; GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.; and ALASKA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC., signatories to the Alaska Intertie Agreement, dated December 23, 1985, hereinafter referred to as "Agreement". The signatory parties are hereinafter referred to as "Utility Participants".

WITNESSETH

WHEREAS THE MUNICIPALITY OF ANCHORAGE, ALASKA, d.b.a. MUNICIPAL LIGHT & POWER; CHUGACH ELECTRIC ASSOCIATION, INC.; THE CITY OF FAIRBANKS, ALASKA, MUNICIPAL UTILITIES SYSTEM; GOLDEN VALLEY ELECTRIC ASSOCIATION, INC.; and ALASKA ELECTRIC GENERATION AND TRANSMISSION COOPERATIVE, INC. are all Utility Participants and signatories to the Alaska Intertie Agreement; and

WHEREAS the ALASKA POWER AUTHORITY is a Participant and signatory to the Alaska Intertie Agreement; and

WHEREAS the signatories to the Alaska Intertie Agreement desire to have a separate agreement involving only Utility Participants with reserve requirement responsibility on the interconnected system;

NOW THEREFORE, the Utility Participants agree as follows:

ARTICLE A
Reserve Capacity

Section A-1.1

A-1.1.1 Each Utility Participant expects and is expected to maintain utility responsibility for its own load and, as a part of such responsibility, shall maintain or otherwise provide for annually, Accredited Capability in an amount equal to or greater than its maximum System Demand for such year plus such Utility Participant's Reserve Capacity Obligation, as set forth in Subsection A-1.1.2 of this Section.

A-1.1.2 The Reserve Capacity Obligation of a Utility Participant, for any year, shall initially be

equal to thirty (30) percent of the projected Annual System Demand of that Utility Participant. The Reserve Capacity Obligation of the Participants may be adjusted from time to time by the Operating Committee.

A-1.1.3 The Operating Committee may determine the annual Accredited Capability for each Utility Participant.

ARTICLE B
Responsibility for Operating Reserve

Section B-2.1 Operating Reserve

B-2.1.1 Each Utility Participant shall provide Spinning Reserve and Non-Spinning Reserve as required by Section B-2.2 of this Article equal to or greater than the Operating Reserve Obligation of the Participant. As soon as practicable, but not to exceed four hours, after the occurrence of an incident which uses Operating Reserves, each Utility Participant shall restore its Operating Reserve Obligation by the procedures determined by the Operating Committee.

B-2.1.2 The Operating Reserves, Operating Reserve Obligation and Utility Participant's Allocation may be modified or adjusted from time to time by the Operating Committee.

Section B-2.2 Total Operating Reserve Obligation

B-2.2.1 The Total Operating Reserve Obligation at any time shall initially be an amount equal to 150 percent of the capability of the largest generating unit contingency in operation on the interconnected systems of the Utility Participants.

B-2.2.1.1 The Spinning Reserve portion of the total Intertie System shall not be less than an amount equivalent to 100 percent of the Declared Capability of the largest generating unit contingency in operation on the interconnected systems of the Utility Participants. The Declared Capability will be as determined by the Utility Participant.

B-2.2.1.2 The balance of the Total Operating Reserve Obligation shall be maintained with Non-Spinning Reserve.

(45 min avail.

B-2.2.2 Generating unit capability for Operating Reserves shall be determined by the following criteria:

a. It shall not be less than the load on the machine at any particular time nor greater than (b) below.

b. It shall not exceed that maximum amount of load (MW) that the unit is capable of continuously supplying for a two-hour period, or immediately supplying through action of automatic governor controls.

B-2.2.3 The criteria specified in this section may be modified or changed by the Operating Committee.

Section B-2.3 Utility Participant's Allocation of Operating Reserves

B-2.3.1 The Operating Reserve Obligation of a Utility Participant shall be that percentage of the Total Operating Reserve Obligation determined by the Operating Committee in accordance with the following formula based on the capability of largest generating unit contingency in operation at each Utility Participant.

B-2.3.1.1 Individual Utility Participant Reserve Allocation Formula

IOR = TOR x Us/Ut

IOR = Individual Utility Participant Operating Reserve Requirement

TOR = Total Operating Reserve Requirement

Us = A Utility Participant largest on-line generation unit capability

Ut = Sum of each Utility Participant's Us

Section B-2.4 Operating Reserve Calculation

B-2.4.1 System Spinning Reserve shall be calculated at any given instant as the difference between the sum of the net capability of all generating units on line in the respective system and the integrated Systems Demand of the system involved.

B-2.4.2 A Utility Participant's Spinning Reserve may be satisfied by an automatically controlled load shedding program. The load shedding program shall assure that controlled load can be dropped to meet the requirements of Spinning Reserve and in such a manner as to maintain system stability and not cause objectionable system conditions or cascading effects in other Utility Participants' systems. The Operating Committee shall review and approve the Utility Participant's load shedding program that will be used to satisfy its Spinning Reserve requirements.

B-2.4.3 The Operating Committee may establish procedures to assure that the Operating Reserve is available on the systems of the Participants at all times. Whenever a Participant is unable to meet its Operating Reserve Obligation, that Utility Participant will immediately, within two hours, advise all other Utility Participants and make arrangements to restore its Operating Reserve Obligation.

B-2.4.4 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.

B-2.4.5 A Participant may arrange for one or more other Utility Participants to supply part or all of its Operating Reserve requirement.

B-2.4.6 In an emergency, any Utility Participant, upon request by another Utility Participant, shall supply to such requesting Utility Participant part or all of its Operating Reserve up to the full amount of its Available Accredited Capability. A Utility Participant experiencing an emergency is not required to maintain its Operating Reserve Obligation. There shall be no obligation of a Utility Participant to supply Operating Reserve if the requesting Utility Participant is not making full use of its Available Accredited Capability.

B-2.4.7 Except as otherwise agreed, a Utility Participant supplying a portion or all of another Utility Participant's Operating Reserve during any month shall be paid by the purchasing Utility Participant an amount equal to whichever is greater of the following:

B-2.4.7.1 110 percent of the Incremental Cost of supplying such service; or

B-2.4.7.2 The Incremental Cost of supplying such service plus one-half of the overall savings involved in such transaction, which overall savings shall be equal to the difference between the Incremental Cost of the selling Utility Participant and the Decremental Cost of the purchasing Utility Participant.

B-2.4.8 If a Utility Participant fails to provide adequate Operating Reserve, other than because of a forced outage, during any such period the deficient Participant shall pay to the other Utility Participants an amount equivalent to two times the cost avoided by the deficient Utility Participant for not starting and/or operating any generating unit or units which would ordinarily be used to provide adequate Operating Reserve. Should the Utility Participant not have adequate Accredited Capability to provide the Operating Reserves, it shall pay the other Utility Participants two times the cost for starting and operating the highest cost generating unit on the deficient Utility Participant's system. This payment shall be shared by the other Utility Participants in the same proportion that their individual Annual System Demand is to the non-deficient Utility Participants' total Annual System Demand. Payments under this section B-2.4.8 of this Article B shall be waived for the first year of operation of the Intertie.

IN WITNESS WHEREOF, the Utility Participants have executed this Addendum No. 1 to the Alaska Intertie Agreement in quintuplet by their authorized officers or representatives as of the day and year first above written.

MUNICIPALITY OF ANCHORAGE,
ALASKA dba MUNICIPAL LIGHT &
POWER

By: Bob Smith
Municipal Manager
(Title)

SUBSCRIBED AND SWORN TO before me on the 23rd day of December, 1985.

Barbara Nunn
Notary Public, State of Alaska
My Commission Expires: 4-11-89

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Robert Mach

General Manager

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Susan Christianson
Notary Public, State of Alaska
My Commission Expires: 11-8-88

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Joyce M Mosby

President of the Board

SUBSCRIBED AND SWORN TO before me on the 17th day of December 1985.

Susan Christianson
Notary Public, State of Alaska
My Commission Expires: 11-8-85

CHUGACH ELECTRIC ASSOCIATION, INC.

By: Joseph M. Tomicich

Vice-President of the Board

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

Susan Christinson
Notary Public, State of Alaska
My Commission Expires: 11-8-88

CITY OF FAIRBANKS, ALASKA
MUNICIPAL UTILITIES SYSTEM

By: [signature]
CITY MANAGER
(Title)

SUBSCRIBED AND SWORN TO before me on the 19th day of December, 1985.

Judith C. Vernon
Notary Public, State of Alaska
My Commission Expires: 10-17-87

GOLDEN VALLEY ELECTRIC
ASSOCIATION, INC.

By: [signature]
Gen. Mgr.
(Title)

SUBSCRIBED AND SWORN TO before me on the 16th day of December, 1985.

Kristi J. Smith
Notary Public, State of Alaska
My Commission Expires: January 11 1987

ALASKA ELECTRIC GENERATION and
TRANSMISSION COOPERATIVE, INC.

By: _____

President
(Title)

SUBSCRIBED AND SWORN TO before me on the 17th day of December, 1985.

_____
Notary Public, State of Alaska
My Commission Expires: 8/21/88