NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Interchange Reference Guidelines

Version 2

RELIABILITY | ACCOUNTABILITY




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Revision Log

Revision Number	Description of changes
1	• Original document
2	• Added *Table of Contents* section • Added *Revision Log* section • Added *Introduction* section • Added *Interchange Terms* section • Notated all NERC Glossary terms within the document • Added *Interchange Coordinator* section • Updated previous section "The Relationship between Interchange Transactions and Interchange Schedules" section into new *Interchange Fundamentals* section • Added *Implementing Interchange* section • Added *Practical Guide to Interchange Implementation* section including references to the e-Tag specifications and schema • Moved and updated previous "Implementing Interchanges Schedules" section to *Other Interchange Schedule Concepts* subsection • Added *A Note on Dynamic Transfers* section • Added *Consideration for Interchange Involving DC Tie Operator* section • Removed previous section "Interchange Schedules within a Multi-Party Regional Agreement or Transmission Tariff"

Introduction

The Interchange Reference Guidelines address and explain the process to implement Interchange. This document is intended to address the following:

1. Defines Interchange terms,
2. Reviews Interchange Transaction and Interchange Schedule concepts,
3. Reviews the theory of implementing Interchange,
4. Reviews the practical processes used to implement Interchange via e-Tag, and
5. Discusses Dynamic Schedules and DC Ties as related to Interchange.

Interchange Terms

NOTE: In this document, the use of the terms are intended to be identical with the NERC "**Glossary of Terms Used in Reliability Standards"** and the NAESB Business Practice Standard WEQ-000 titled **"Abbreviations, Acronyms, and Definition of Terms".** The definitions listed in the two documents above should prevail if there are any discrepancies. The NERC **"Glossary of Terms Used in Reliability Standards"** is posted at the NERC website in the same location as the Reliability Standards under the link name **"Glossary of Terms"**.

The following terms are used in this document and not defined in standardized industry *Business Practices*:

Market Assessment – The evaluation and verification of the commercial details of *Interchange.*
Market Operator – An entity that is responsible for the implementation of an organized market and submits market adjustments based on market outcomes. A Market Operator must be registered in the Electric Industry Registry (EIR) in order to submit market adjustments.

Wide Area Reliability Tool — This generic term is intended to reflect in a "tool neutral" manner those wide-area reliability assessment tools (such as the *Interchange Distribution Calculator (IDC)* for the Eastern *Interconnection*) acknowledged by NERC as a decision making tool among various reliability entities.

Reliability Assessment – The evaluation and verification of the reliability details of *Interchange*

All terms from the NERC Glossary and defined above are capitalized and italicized in this document. Certain other terms from other locations, such as the e-Tag specification, may be capitalized as well.

Interchange Coordinator

The NERC Functional Model lists the Interchange Coordinator (IC) as the function responsible for communicating *Arranged Interchange* for reliability evaluation and for communicating *Confirmed Interchange* to be implemented between *Balancing Authorities (BAs)*. However, NERC reliability standards refer to the *Interchange Authority (IA)*. These guidelines do not make reference to the *IA* or the IC, but instead refers to the *Sink Balancing Authority* as the responsible entity.

Interchange Fundamentals

The Relationship between Interchange Transactions and Interchange Schedules

Purchasing-Selling Entities (PSEs) and in some instances *BAs* “arrange” *Interchange Transactions* by buying and selling energy and capacity and arranging for *Transmission Services*. A compilation of these arranged *Transactions* are forwarded by the *PSE* to the *Sink Balancing Authority*. Reliability entities assess and “approve” or “deny” *Interchange Transactions* based on reliability criteria, arrangements for *Interconnected Operations Services*, and *Transmission* rights. To “implement” the *Interchange Transaction*, all affected reliability entities incorporate the *Interchange Transaction* into their *Interchange Schedules* as explained on the following pages.

In this example, there are three *Interchange Transactions* (IT1, IT2, and IT3) that result in a number of *Interchange Schedules* between *BAs* A, B, C, and D. (Refer to Figure A on the right and Table 1 below. For simplicity, we are ignoring losses.)

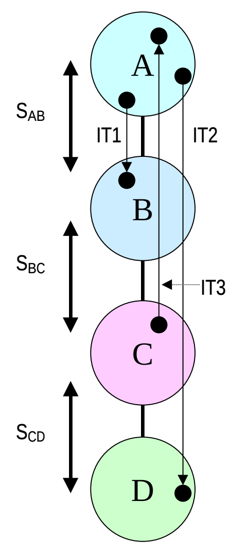

Figure A - Interchange Transactions and Schedules

Interchange Transaction 1 (IT1)

BA A is the *Source Balancing Authority* for *Interchange Transaction* 1 (IT1), and *BA* B is the *Sink Balancing Authority*. To make IT1 occur, *BA* A implements an *Interchange Schedule* with *BA* B ($S_{AB\text{-}IT1}$). In this case, the *Source Balancing Authority* A is the *Sending Balancing Authority*, and the *Sink Balancing Authority* B is the *Receiving Balancing Authority*.

Interchange Transaction 2 (IT2)

BA A is also the *Source Balancing Authority* for *Interchange Transaction* 2 (IT2). *BA* D is the *Sink Balancing Authority* for this *Interchange Transaction*. B and C are *Intermediate Balancing Authorities*. The resulting *Interchange Schedules* are from *Sending Balancing Authority* A to *Receiving Balancing Authority* B ($S_{AB\text{-}IT2}$), *Sending Balancing Authority* B to *Receiving Balancing Authority* C ($S_{BC\text{-}IT2}$), and *Sending Balancing Authority* C to *Receiving Balancing Authority* D ($S_{CD\text{-}IT2}$).

Interchange Transaction 3 (IT3)

BA C is the *Source Balancing Authority* for *Interchange Transaction* 3 (IT3), and *BA* A is the *Sink Balancing Authority*. B is the *Intermediary Balancing Authority*. To make IT3 occur, *Sending Balancing Authority* C implements an *Interchange Schedule* with *Receiving Balancing Authority* B ($S_{CB\text{-}IT3}$), and *Sending Balancing Authority* B implements an *Interchange Schedule* with *Receiving Balancing Authority* A ($S_{BA\text{-}IT3}$).

Net Schedules

BAs A and B can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{AB\text{-}IT1}$ and $S_{AB\text{-}IT2}$ and $S_{BA\text{-}IT3}$. *BAs* B and C can calculate a *Net Interchange Schedule* between these two *BAs* by adding $S_{BC\text{-}IT2}$ and $S_{CB\text{-}IT3}$.

The *Net Scheduled Interchange* for A is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$. The *Net Scheduled Interchange* for B is $S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3} + S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$.

Balancing Authority	Sink Balancing Authority for:	Source Balancing Authority for:	Sending Balancing Authority for:	Receiving Balancing Authority for:	Net Interchange Schedules	
A	IT3	IT1, IT2	IT1, IT2	IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$	Match
B	IT1		IT2, IT3	IT1, IT2, IT3	$S_{AB\text{-}IT1} + S_{AB\text{-}IT2} + S_{BA\text{-}IT3}$ $S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$	Match
C		IT3	IT2, IT3	IT2	$S_{BC\text{-}IT2} + S_{CB\text{-}IT3}$ $S_{CD\text{-}IT2}$	
D	IT2			IT2	$S_{CD\text{-}IT2}$	Match

Table 1 - Relationship Between Balancing Authorities, Interchange Schedules, and Interchange Transactions

Implementing Interchange

Interchange Transactions are the representation of a *PSE* or *BA* arranging for energy and capacity transfers between different parties. From a real-world perspective, these compiled arrangements are known as a *Request for Interchange (RFI)*. The *RFI* goes through two types of assessment: *Market Assessment* and *Reliability Assessment*.

Prior to the assessment stages, the *PSE* puts together the business arrangements for the *Interchange* with *Transmission Service Providers (TSPs)*, *Generation Providing Entities(GPEs)*, and *Load-Serving Entities (LSEs)* and may obtain preliminary reliability approvals from *BAs*, *TSPs*, and *Reliability Coordinators (RCs)* where required. At this stage, *Agreements* (including *Transmission Service* reservations) are aggregated into a single request. This aggregated information, the *RFI*, is sent to the *BAs*, *PSEs*, and *TSPs* and begins both the *Market Assessment* and *Reliability Assessment*.

During the *Market Assessment* and *Reliability Assessment*, the *RFI* proposed by the *PSE* is evaluated by the approval entities to ensure all the proper information has been given for both commercial and reliability issues and that system conditions allow for approval. Note that the actual *RFI* submission can be assessed and approved or denied by both market and reliability entities.

In both the NERC Standards and NAESB Business Practice Standards, *RFIs* go through several transitions as they are evaluated. Prior to either assessment period, any compiled arrangements are known only as *RFI*. Once the *RFI* is passed to the reliability and market entities to begin evaluation during the *Reliability Assessment* and *Market Assessment*, respectively, then the *RFI* becomes known as *Arranged Interchange*. If approvals are obtained from all entities with approval rights during the *Reliability Assessment* and *Market Assessment*, then the *Arranged Interchange* transitions to *Confirmed Interchange*. *Confirmed Interchange* has obtained all necessary approvals and is ready to be implemented in the *Net Scheduled Interchange* portion of all impacted *BAs*. Once the *Ramp* start time is reached, *Confirmed Interchange* transitions to *Implemented Interchange*. At that point in time, each impacted *BA* will implement the *Implemented Interchange* value into their *Area Control Error (ACE)* equation as part of the *Net Scheduled Interchange*.

The "Normal" Process of Coordinating Interchange

Figure B below shows the normal, reliability-related steps in coordinating *Interchange*. When the *RFI* is submitted to the *Sink Balancing Authority*, it is processed through the *Market Assessment* and *Reliability Assessment*. Once approved during the assessments, the *Sink Balancing Authority* electronically distributes the *Interchange* status, and the *Interchange* information is entered into the *Wide Area Reliability Tool* and into the *ACE* equations of the applicable *BAs*. Note that the NERC INT Standards require coordination of any *Interchange* with any DC tie operating *BA* on the *Scheduling Path*.

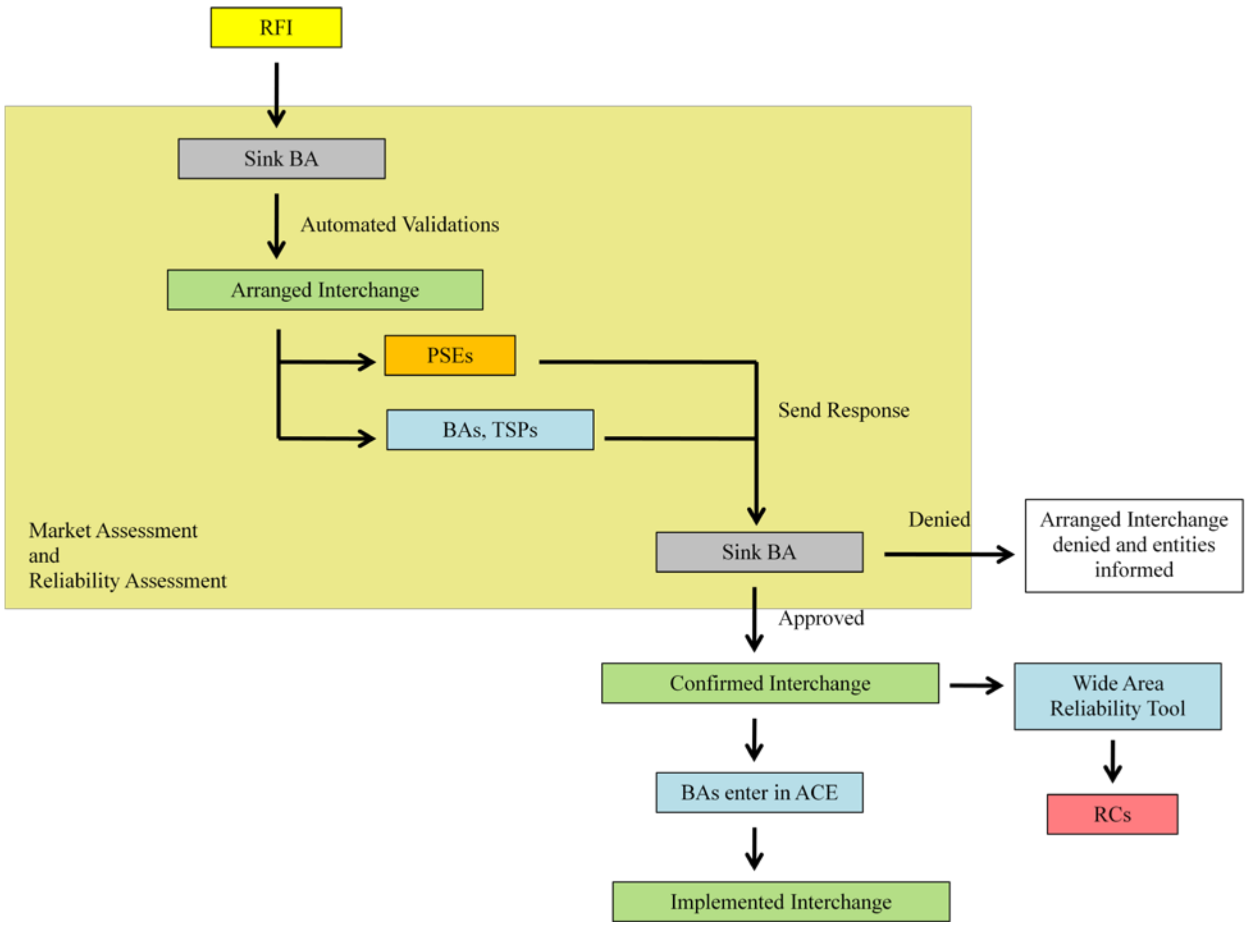

Figure B - Processing on Initial RFI Submission

Interchange Changes for Reliability Reasons

Once *Arranged Interchange* has transitioned to the *Confirmed Interchange* or *Implemented Interchange*, it is entirely possible that the *Interchange* parameters (i.e., MW, *Ramp* start and stop, duration, etc.) may need to change for reliability reasons. The change to *Confirmed Interchange* or *Implemented Interchange* does not eliminate the necessity for coordination. While Figure B shows the coordination that takes place when an *RFI* is initially submitted, Figure C shows coordination steps to effect a change to *Confirmed Interchange* or *Implemented Interchange*.

Interchange created to address an actual or anticipated reliability-related risk or as part of an energy sharing *Agreement* is implemented first without submitting an *RFI* and then follows the submission and transition steps shown in Figure B. *Interchange* modified to address an actual or anticipated reliability-related risk, known as *Reliability Adjustment RFI*, is implemented first and then follows the submission and transition steps shown in Figure C. Note that when submitting *Reliability Adjustment RFI*, only a *Reliability Assessment* occurs since approval rights are only granted to the *Source Balancing Authority* and *Sink Balancing Authority*.

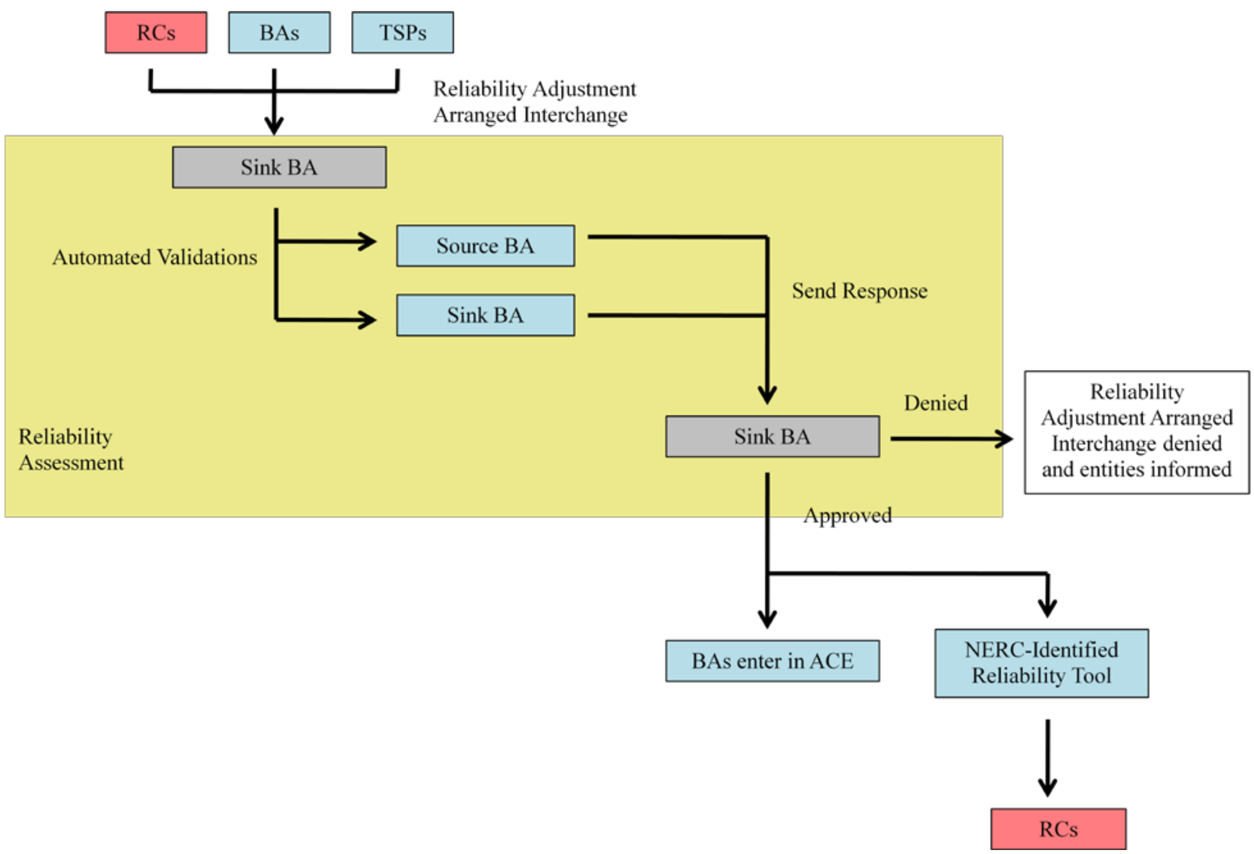

Figure C – Processing of Reliability Adjustment RFI Request

Interchange Changes for Market Reasons

Figure D shows a change (e.g., cancel, increase MW, decrease MW, change *Ramp* or duration info, etc.) initiated by the *PSE*, *BA*, or *Market Operator* for non-reliability reasons once the *Arranged Interchange* has transitioned to *Confirmed Interchange* or *Implemented Interchange*. In this case, the *Confirmed Interchange* or *Implemented Interchange* will undergo the same *Market Assessment* and *Reliability Assessment* as performed when submitting the initial *RFI*. Subsequent steps also follow the same process.

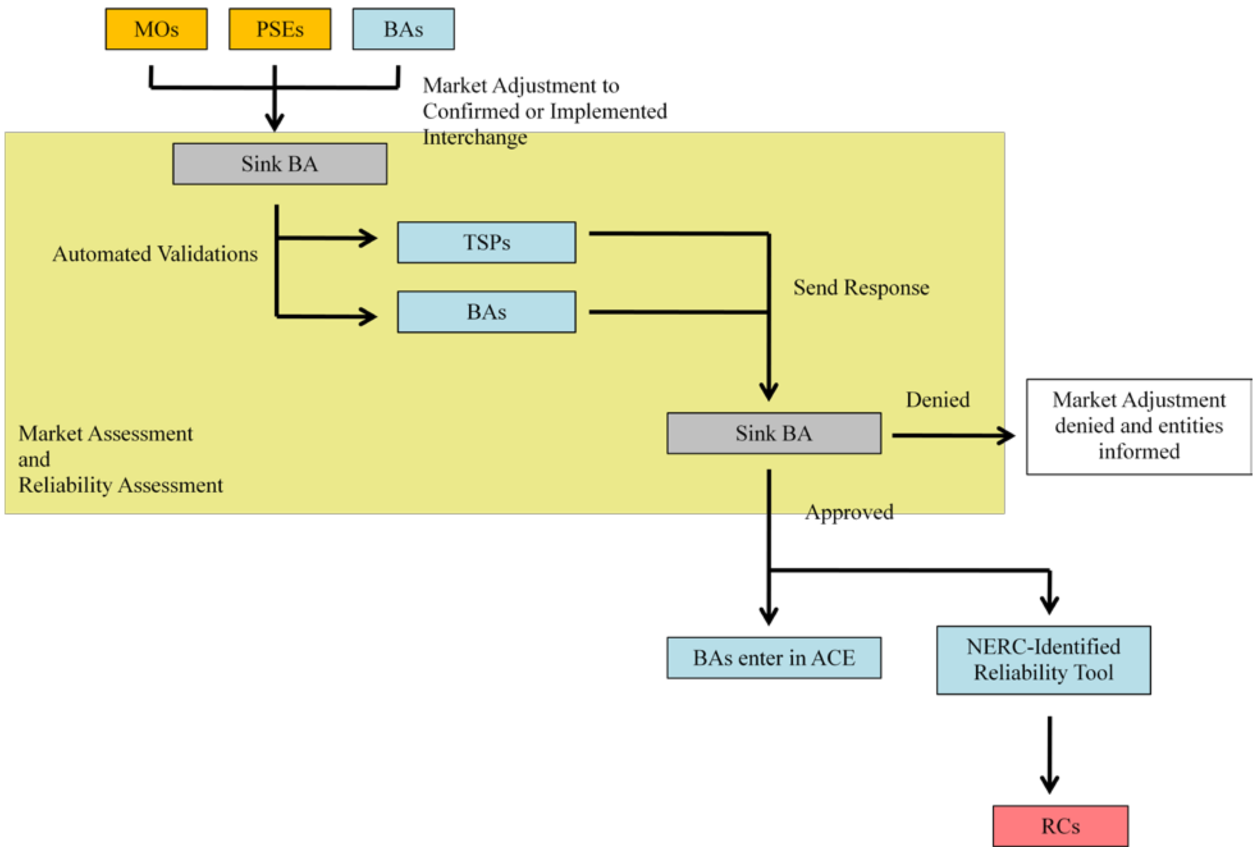

Figure D – Processing of Market Adjustment Request

Practical Guide to Interchange Implementation

The previous sections of this document detail some of the concept behind accomplishing *Interchange*. The first section discussed *Interchange* in terms of how it is transferred between different entities. The second section discussed the way *Interchange* is processed from a theoretical perspective and using terms that are not used during the daily processing of *Interchange*. This section will describe how *Interchange* is practically accomplished on a daily basis.

Interchange is a coordinated process. This process involves arranging for transferring power from a source to a sink point and arranging for the *Transmission* rights across all impacted entities. As this practice grew in volume, the industry moved to adopt technology that would facilitate the business and allow *RCs* to manage *Transmission* congestion. The systems that facilitate the business are based on the e-Tag specifications and schema. Systems implementing the e-Tag specifications allow for entities involved in *Interchange* to assemble an *RFI* into an e-Tag and then send it out for the required approvals before implementation. Any entity that has registered a Tag Agent Service in the EIR can assemble and submit an e-Tag. Typically an entity related to the *Sink Balancing Authority* is responsible for gathering the power deals and *Transmission* rights for submission.

The e-Tag Specifications and Schema are maintained by NAESB and assist in providing the processes required by the NERC and NAESB standards related to *Interchange*. The Joint Electric Scheduling Subcommittee has the primary obligation of monitoring and modifying the e-Tag Specifications and Schema and also has reporting obligations to both the NAESB Executive Committee and the NERC Interchange Subcommittee.

A Note on Wide Area Reliability Tools

In order to maintain reliability, *Interchange* must be coordinated with several entities other than those involved in the transaction. One type of monitoring is accomplished by *Wide Area Reliability Tools*; examples of such tools include the IDC in the Eastern *Interconnection* and webSAS in the Western *Interconnection*. These tools are used for managing congestion when *RCs* (Eastern *Interconnection*) or *BAs* (Western *Interconnection*) issue adjustments to *Interchange* to relieve congested paths in real-time, Each *Wide Area Reliability Tool* has a specific set of rules on how *Interchange* is adjusted.

Functions Detailed in the e-Tag Specifications

The e-Tag Specifications and Schema discuss the practices and technical details needed in the systems that drive e-Tag. Systems implementing the e-Tag specifications are based on transferring data over the Internet to gather and distribute approvals. Most entities implement the e-Tag specifications by contracting with vendors that have developed these systems. The e-Tag Specifications details three main functions that are needed, and all three functions are accomplished by most vendors with their software:

1. Tag Agent - Software component used to generate and submit new e-Tags, Corrections, and Profile Changes to an Authority and to receive State information for these requests.

2. Tag Approval - Software component used to indicate individual approval entity responses when requested by Authority Service as well as submit Profile Changes.

3. Tag Authority - Software component that receives Agent and Approval Requests and Responses and forwards them to the appropriate Approval Services. Also maintains master copy of an e-Tag (all associated Requests), the Composite State of the e-Tag, etc. and responds to queries regarding the e-Tags in its possession.

These different functions ensure that e-Tag submission, approval, and coordination are all handled properly.

Parts of an e-Tag

An e-Tag has several required components in order to be valid. Without these components, the necessary information would not be conveyed to the approving entities. Most software has checks in place to ensure the proper information is supplied. The required parts of an e-Tag include:

1. e-Tag ID – Each e-Tag has a unique e-Tag identifier based on four key attributes:
    a. Source Balancing Authority Code
    b. PSE Code (Tag Author PSE)
    c. Unique transaction identifier
    d. Sink Balancing Authority Code

    The codes specified above for *BAs* and *PSEs* come from the EIR which will be detailed below.

2. Transaction Types – There are several variations in the transaction type that can be chosen for an e-Tag. Transaction types assist in noting the purpose and implementation of a particular e-Tag. Specific *Transmission* tariffs and *Business Practices* should be referenced to determine which of the following transaction types should be selected. e-Tag recognizes the following transaction types:
    a. Normal: These are the normal energy *Schedules* and should represent the largest number of e-Tags. They will include *Schedules* that use *Point to Point Transmission Service*, *Network Integration Transmission Service*, or grand-fathered service under a regional tariff.
    b. Dynamic: A *Dynamic Schedule* is scheduled using an expected value but the actual energy transfer is determined in *Real-time* by separate communications external to the e-Tag system. Also included in this type will be regulation energy *Schedules* and energy imbalance *Schedules*. The e-Tag should contain the expected average energy in the energy profile and contain the maximum expected energy in the Transmission Allocation. Dynamic e-Tags may be adjusted by the *Source Balancing Authority*, *Sink Balancing Authority*, or e-Tag author up to 168 hours in the past using a market adjust to set the actual *Interchange Schedule* value. For additional information related to implementation of *Dynamic Schedules,* please see the Dynamic Transfer Reference Guidelines.

c. Emergency: *Emergency Schedules*, including reserve sharing, *Spinning Reserve*, and supplemental reserve may be scheduled as *Emergency Schedule* Type. For additional detail of when to use Emergency type, see the NERC Glossary of Terms for *Emergency RFI* as well as *Emergency* and *Energy Emergency.*

d. Loss Supply: Loss Supply type is used for customers to self-supply losses. This type is used to differentiate between a loss *Schedule* and a normal *Schedule*. Some tariffs presently require that *Schedules* for losses require different treatment than *Schedules* for the associated energy.

e. Capacity: Capacity type is typically used for entities to import *Operating Reserves* from outside their *Reserve Sharing Group* but may also be used to arrange for purchases or sales of *Spinning Reserve* and supplemental reserve between other entities. This type of e-Tag may be activated upon contingency with zero *Ramp* durations.

f. Pseudo-Tie: A *Dynamic Transfer* implemented as a *Pseudo-Tie* rather than a *Dynamic Schedule*. This type is used in the same way as a Dynamic e-Tag. These e-Tags may be adjusted in the same manner as Dynamic transaction type e-Tags. For additional information related to implementation of *Pseudo Ties,* please see the Dynamic Transfer Reference Guidelines.

g. Recallable: A WECC-only transaction type typically used for "interruptible" or "non-firm" transactions. Adjustments to this transaction type only require *Source Balancing Authority* & *Sink Balancing Authority* approval..

3. Market Segments – Each e-Tag has a section to identify those portions of the path that are associated with the tracking of title and responsibility. Market Segments contain information that describes the market information, such as the identity of the market participant, the firmness of energy the market participant is delivering, and the physical segments the entity is responsible for providing. Market Segments must be listed in order from the *PSE* responsible for generation to the *PSE* responsible for *Load*. There will only be one market segment for generation and one segment for *Load*, but there can be multiple intermediate market segments. Market Segments can describe the responsibility for scheduling actual power delivery, or it can describe non-physical title transfers. These are seen when a market participant takes financial possession for the energy commodity but does not physically move that energy before transferring possession to another financially responsible party. When this occurs, the market segment will not contain any physical segments.

4. Physical Segments – e-Tags also have a section to represent those portions of the path that are physical in nature and represent a movement of energy. There are three types of Physical Segment:

   a. Generation - Generation Segments contain information that describes a generation resource, such as the location of the generation, the firmness of the energy supplied by the resource, and contract references that identify the resource commitment.

b. Transmission – Transmission Segments contain identification that describes a *Transmission Service*, such as the identity of the provider, the *Point of Receipt (POR)* and *Point of Delivery (POD)* of the service, the firmness of the service, simple loss information, and contract references that identify the service commitment.
Load - Load Segments contain information that describes a *Load*, such as the location of the *Load*, the interruptability of the *Load*, and contract references that identify the *Load* obligation. All definitions for information in the segments above must be valid in the EIR which will be described below. Physical Segments must be listed in order from Generation to *Load*. Generation Segments must always be listed first, while Load Segments must be listed last. e-Tags may only have one Generation Segment and one Load Segment. All physical segments must reference a parent market segment, identifying the market entity responsible for the physical segment. These references must also be in an order that matches that described by the market segments. An optional field in the Physical Segments is Scheduling Entities. Many *TSPs* require that e-Tags illustrate not only the contractual relationship between the *TSP* and the *Transmission Customer* but also the internal scheduling information to implement the *Transmission Service* sold under their *TSP's Transmission* tariff. To this end, Scheduling Entities may be defined for a particular Transmission segment.

5. Profile Set – The Profile Sets, commonly referred to as the Energy Profile, section of an e-Tag defines the level at which transactions should run as well as the factors that set those levels. Profiles are specified as a series of time-ordered segments of duration associated with a particular profile. Profiles may optionally contain *Ramp* duration (in minutes) associated with both start time and stop time. The *Ramp* stop time is not needed (and is ignored) in any profile except for the last profile. The *Ramp* duration specifies the number of minutes over which the generator will change from the previous block level to the current block level. *Interchange Schedule* ramping is executed between *BAs* using straddle *Ramp* methods as defined below in "Other Interchange Schedule Concepts".. The *Ramp* duration exists in the e-Tag in order to provide a vehicle by which *Ramp* duration may be exchanged between entities. The Profile Set of an e-Tag is influenced by two different profiles:

    a. Market Limit - The Market Limit defines the level at which the e-Tag author wishes the transaction to run. This level can be used to specify an initial value for a *Dynamic Schedule* as well as a simple level at which the transaction is to be run.

    b. Reliability Limit – The Reliability Limit defines the maximum allowable level at which a transaction may run when that transaction has been identified by a *RC* or other reliability entity as being limited by some *Constrained Facility*. This limit is typically used to indicate *Curtailments*.

    The lower of the most recent approved Market Limit and most recent approved Reliability Limit sets the Current Level on an e-Tag. The Current Level contains the level at which the transaction should be running based on all approved Requests processed by the Authority.

6. Transmission Allocation - Transmission Allocations are a type of e-Tag profile set that defines the way in which market participants will fill their capacity commitments with *Transmission Service* reservations. Transmission Allocations specify a particular reservation, the provider associated with the reservation, and profiles associated with that reservation that describe how the reservation should be consumed. Transmission Allocations must always be associated with Transmission Physical Segments; association with other segments (such as Generation or Load) is not allowed. The Maximum Reservation Capacity associated with each physicalsegment should be greater than or equal to the energy profile. The Transmission Allocation for all Transmission segments must be greater than or equal to the minimum of the *POR* profile and *POD* profile for that segment. One or more *Transmission Service* reservations may be utilized together in what is known as stacking. There are two types of stacking:

   a. Vertical Stacking – A market participant may have two or more *Transmission Service* reservations flowing from the same source to the same sink for the same time period. In this case, Vertical Stacking can be used to tag a Profile Set equal to the combined capacity of the two *Transmission Service* reservations. For example, an e-Tag author can use two 50 MW *Transmission Service* reservations on the same e-Tag to cover 100 MW on the Energy Profile. Figure E shows an example of how Vertical Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	50	50

Figure E – Vertical Stacking

   b. Horizontal Stacking – A market participant may have two or more reservations flowing from the same source to the same sink for different hours. In this case, Horizontal Stacking can be used to tag a Profile Set for the entire time range as long as the capacity of the *Transmission Service reservation* for each hour is not exceeded. For example, an e-Tag author can use two 100 MW *Transmission Service* reservations in subsequent hours to cover 100 MW on the Energy Profile for both hours. Figure F shows an example of how Horizontal Stacking appears on an e-Tag.

Start	Stop	Energy Profile	Transmission Allocation	
Time	Time	MW	Reservation 1	Reservation 2
12:00	13:00	100	100	
13:00	14:00	100		100

Figure F – Horizontal Stacking

7. Loss Accounting – The Loss Accounting section of an e-Tag specifies the manner in which losses should be accounted for over a specified period of time. Over time, an e-Tag Author may elect to specify different choices for how losses will be provided. Usually each *Transmission Operator* across which an e-Tag flows will have specified transactions which require losses and also usually detail what type of losses are required. The two main types of losses in the industry today are Financial Losses and In-Kind Losses. The type of losses provided is dependent upon each Transmisson Provider’s tariff / contract.

A Note on the Electric Industry Registry

Several sections detailing the required parts of an e-Tag make reference to the EIR. The EIR is a database where participants in the e-Tagging process register information involved in the process. This registration includes entity names and codes, such as *PSEs*, *BAs*, and *TSPs*. Other pieces of information that are registered include Source and Sink names used on e-Tags, authorized *PSEs* for specific sources and sinks, and valid products for use on e-Tags. The EIR is managed by NAESB.

E-Tag Approval and Timing Process

Once an e-Tag is submitted by an author, it is distributed by the Tag Authority to the appropriate approval entities. For new e-Tag submissions and modifications to e-Tags made by *PSEs*, the *PSEs*, *BAs*, *TSPs* specified on the e-Tag have approval rights. For e-Tag modifications requested for reliability reasons (*Curtailments* and reloads), only the *Source Balancing Authority* and *Sink Balancing Authority* have approval rights. All reliability entities must provide their approval for an e-Tag or modification to an e-Tag to be implemented.

In order to manage this approval process, the industry has developed guidelines around the timing of submitting and processing the approvals. These timing rules are part of the NERC Interchange Standards as well as the NAESB Wholesale Electric Quadrant Business Practice Standards. There are differences in the timing tables between the Eastern *Interconnection* and ERCOT *Interconnection* versus the Western *Interconnection*. Therefore, two different tables are used to show these timing differences.

Any e-Tag that is submitted or modified "On-Time" as defined in the NERC INT standards timing tables, as well as any modification to an e-Tag submitted for reliability reasons, must be evaluated. All Late or *After the Fact (ATF)* e-Tag submissions should be evaluated as time permits.

Other Interchange Schedule Concepts

1. **Ramp duration**. When the *Sending Balancing Authority* and *Receiving Balancing Authority* implement an e-Tag between each other in their respective *ACE* equations, the *BAs* must begin their generation adjustments at the same time using the same *Ramp* durations. A mismatch of these parameters will cause a *Frequency Error* in the *Interconnection*. The standard *Ramp* for e-Tags in the Eastern and ERCOT *Interconnections* is 10 minutes across the e-Tag start time (straddle), and the standard *Ramp* for e-Tags in the Western *Interconnection* is 20 minutes across the tag start time (straddle). Non-standard *Ramps* may be used as long as all *BAs* involved in the *Transaction* agree to the *Ramp* stated on the e-Tag. Figure G shows standard *Ramps*.

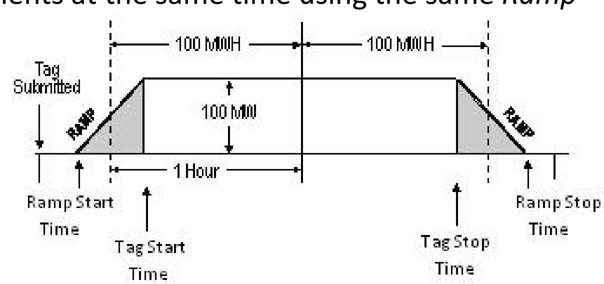

Figure G - Interchange Schedule resulting from 100 MW Interchange Transaction for two hours showing ramps, energy profiles, and energy accounting for each hour.

2. **Starting and ending times**. Most e-Tags generally start and end on the *Clock Hour*. However, *PSEs* may submit e-Tags that start and/or stop at other times beside the *Clock Hour*. *BAs* and *TSPs* should try to accommodate these intra-hour e-Tags. Figure G shows a two hour *Interchange Schedule* starting and stopping at the top of the hour.

3. **Interchange accounting**. All *BAs* must account for their *Interchange Schedules* the same way to enable them to confirm their *Net Interchange Schedules* each day with their *Adjacent Balancing Authorities* as required in NERC BAL Standard **BAL-006 (Inadvertent Interchange)**. *BAs* traditionally use "block" *Interchange Schedule* accounting. This accounting method ignores straddle *Ramp* times and instead uses the *Transaction* start and stop times. This, in effect, moves the energy associated with the starting and ending *Ramps* into their adjacent starting and ending *Clock Hours* of the *Interchange Schedule*. Figure H illustrates the block accounting principle.

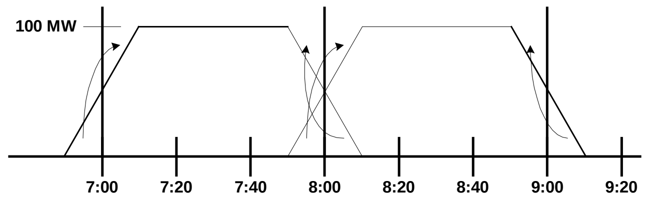

Figure H - Block accounting moves the ramp energy into the adjacent Clock Hours.

A Note on Dynamic Transfers

Dynamic Schedules and *Pseudo-Ties are special Transactions* that rely on time-varying energy tra*nsfers. While e-Tag prov*ides for both transac*tion types, many tagging requi*rements for both types are addressed in regional criteria and *Transmission Operator Business Practices. For more detai*l on these types of *Transactions*, see the NERC Dynamic *Tra*nsfer Guidelines document.

Consideration for Interchange Involving DC Tie Operators

Per the NERC INT Standards, the *Sending Balancing Authorities* and *Receiving Balancing Authorities will co*ordinate *Interchange with an*y DC tie operating *BA*. Note that DC tie operators that are *Intermediate Balancing Authorities* would receive the *Interchange Schedule* information and be subject to the applicable INT standards. The DC Tie operator also would be responsible for notifying the *Sink Balancing Authority* of a DC tie trip and the associated Interchange modification