NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Interchange Reference Guidelines
Version 4

to ensure the reliability of the bulk power system

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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.

This document does not take the place of any NERC standards and is not all-encompassing in terms of complying with those standards. (Andy checking for standard NERC language)

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 Arranged Interchange (e.g. required purchase, sale, and Transmission Service arrangements) during initial Request for Interchange and the evaluation and verification of the commercial details of a Market Adjustment to Confirmed and Implemented 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 (currently TSIN) 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 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 Arranged Interchange (e.g. path contiguity, ramping ability, and Transmission system availability) during initial Request for Interchange and the evaluation and verification of the reliability details of a Reliability Adjustment Arranged Interchange to Confirmed and Implemented Interchange.

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

Interchange Fundamentals

The Relationship between Interchange Transactions and Interchange Schedules

Purchasing-Selling Entities (PSEs) and in some instances Balancing Authorities (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 and 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 Balancing Authority Areas A, B, C, and D. (Refer to Figure A on the right and Table 1 below. For simplicity, we are ignoring losses.)

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

Interchange Transaction 2 (IT2)
Balancing Authority A is also the Source Balancing Authority for Interchange Transaction 2 (IT2). Balancing Authority 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 ($S_{CD\text{-}IT2}$).

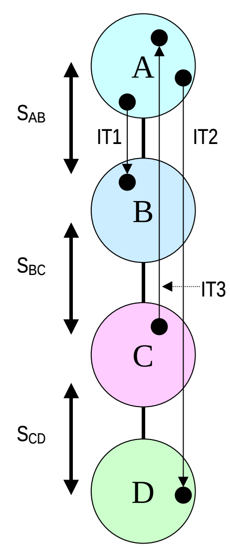

Figure A - Interchange Transactions and Schedules

Interchange Transaction 3 (IT3)

Balancing Authority C is the Source Balancing Authority for Interchange Transaction 3 (IT3) and Balancing Authority 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 to Receiving Balancing Authority A ($S_{BA\text{-}IT3}$).

Net Schedules

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

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), Generators, and LSEs and may obtain preliminary reliability approvals from BAs, TSPs, and RCs where required. At this stage, Agreements (including Transmission reservations) are aggregated into a single request. This aggregated information 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, the 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 BA, it is processed through the Market Assessment and Reliability Assessment. Once approved during the assessments, the Sink BA 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.

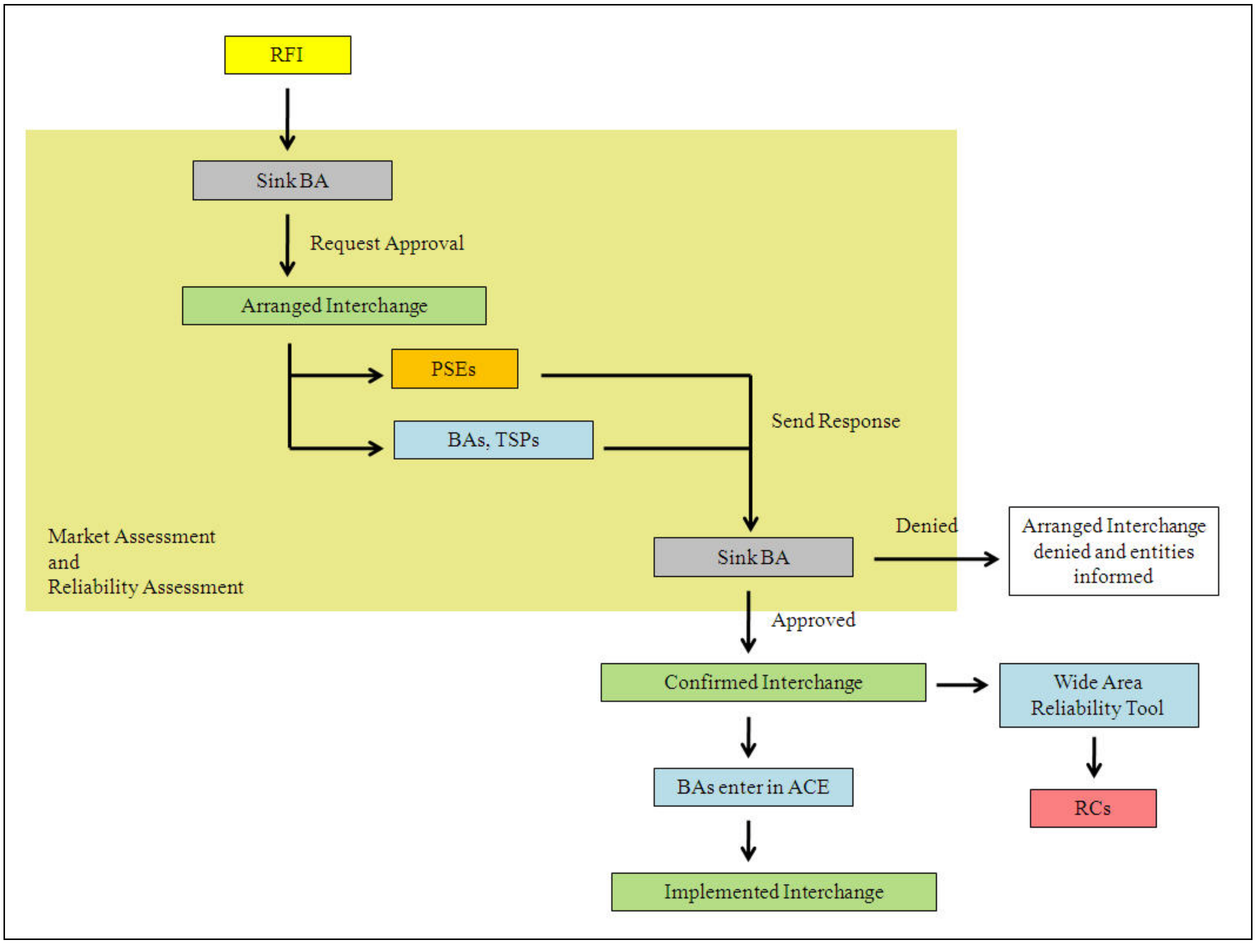

Figure B - Processing on Initial RFI Submission

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 a 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 a 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 Arranged Interchange, is implemented first and then follows the submission and transition steps shown in Figure C. Note that when submitting Reliability Adjustment Arranged Interchange, only a Reliability Assessment occurs since approval rights are only granted to the Source BA and Sink BA (and any DC-tie operating BA).

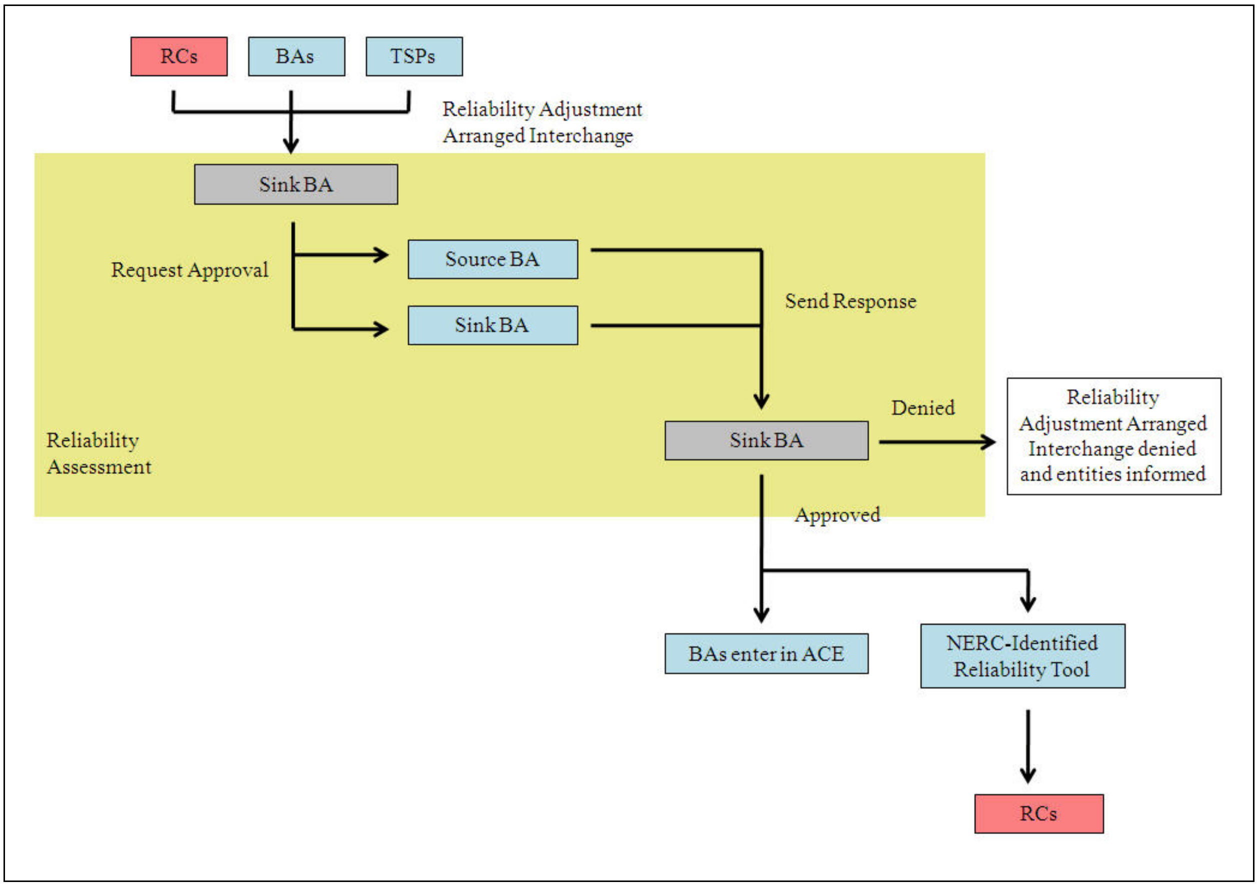

Figure C – Processing of Reliability Adjustment Arranged Interchange Request

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 PSE will undergo the same Market Assessment and Reliability Assessment as performed when submitting the initial RFI. Subsequent steps also follow the same process.

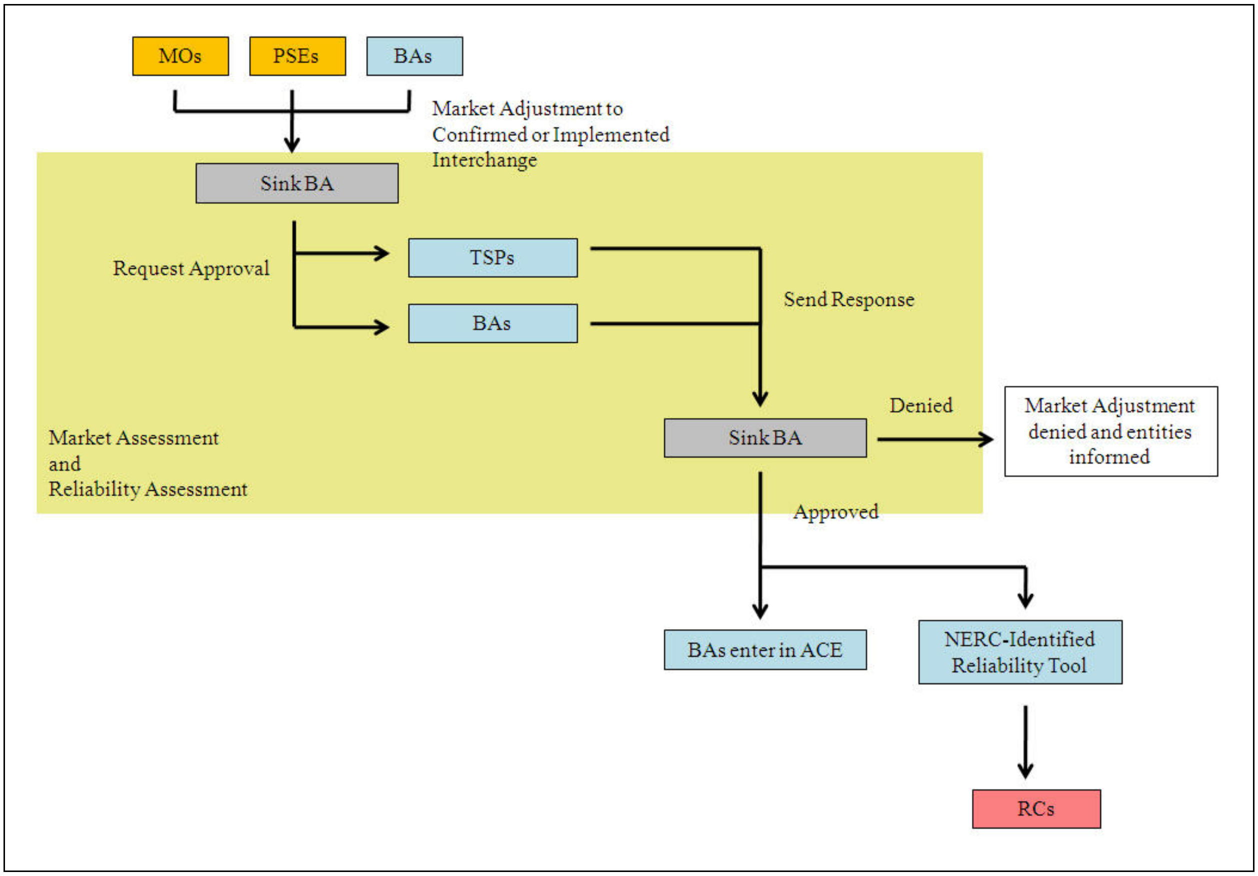

Figure D – Processing of Market Adjustment Request

Practical Guide to Interchange Implementation

The previous sections of this document detail some of the theory 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 Reliability Coordinators to manage Transmission congestion. E-Tag allows for entities involved in Interchange to assemble a RFI into an e-Tag and then send it out for the required approvals before implementation. Any entity registered in the Electric Industry Registry (EIR) can assemble and submit an e-Tag. Typically an entity related to the Sink BA 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.

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. E-Tag is based on transferring data over the Internet to gather and distribute approvals. Most entities involved in using e-Tag have contracted with vendors that have developed these systems. The e-Tag Specifications details three main functions that are needed, and all three 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 Electric Industry Registry 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 of a particular e-Tag. 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. These Schedules are included in the IDC and are subject to TLR Curtailment.

    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 BA, sink BA, or e-Tag author up to 168 hours in the past using a market adjust to set the actual Interchange value.

    c. Emergency: Emergency Schedules, including reserve sharing, Spinning Reserve, and supplemental reserve may be scheduled as Emergency Schedule Type. Another kind of emergency Schedules is execution of an operating guide that implements Schedules in response to a loading problem. For example, an RTO based emergency re-dispatch that lasts longer than an hour involving multiple BAs. Typically, Emergency Schedules would not require reservations before being used where Capacity Benefit Margin had been calculated to allow for this reserve sharing.

    d. Loss Supply: Used for customers 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: 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.

Pseudo-Tie: A Dynamic Transfer implemented as a Pseudo-Tie rather than a Dynamic Schedule. Used in the same way as a Dynamic e-Tag. These tags may be adjusted in the same manner as Dynamic transaction type e-Tags.

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.

   c. 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 Electric Industry Registry 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 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 above. The Ramp duration exists in the e-Tag in order to provide a vehicle by which Ramp duration may be exchanged between entities. Ramps may not overlap. 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 Reliability Coordinator or other reliability entity as being limited by some constraint. This limit is typically used to indicate Curtailments.

   The lower of the Market Limit and 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 in order of receipt by the Authority.

6. Transmission Allocation - Transmission Allocations are a kind of e-Tag profile set that defines the way in which market participants will fill their capacity commitments with Transmission 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 physical segment 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 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 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 reservations. For example, an e-Tag author can use two 50 MW Transmission 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 reservation for each hour is not exceeded. For example, an e-Tag author can use two 100 MW Transmission 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.

A Note on the Electric Industry Registry

Several sections detailing the required sections of an e-Tag make reference to the Electric Industry Registry (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 TPs. 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. Currently, the industry uses the Transmission System Information Networks (TSIN) as the EIR.

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 BA and Sink BA (and any DC-tie operating BA) have approval rights. All entities with approval rights 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. The tables can be found in the NERC INT standards.

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 other e-Tag submissions, (marked as Late or ATF) should be evaluated as timing allows for approval entities.

Other Interchange Schedule Concepts

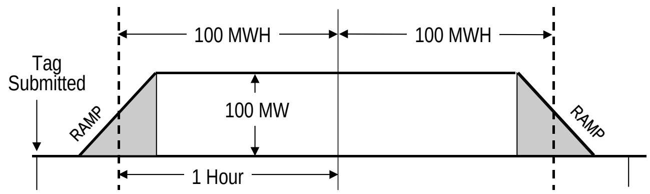

Figure G - Interchange Schedule resulting from 100 MW Interchange Transaction for two hours showing ramps, energy profiles, and energy accounting for each hour.

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 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.

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 BAs as required in NERC BAL Standards titled **"Inadvertent Interchange**." BAs traditionally use "block" Interchange Schedule accounting, which ignores the straddle Ramps times and 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.

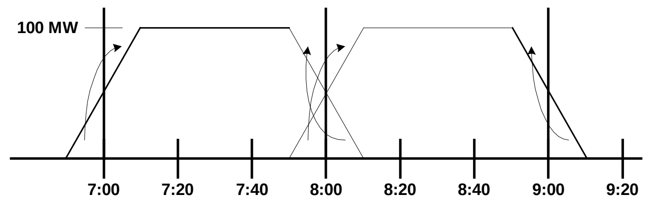

Figure H - Block accounting moves the ramp energy into the adjacent Clock Hours.

A Note on Dynamic Transfers

Dynamic Schedules and Pseudo-Ties are special transactions that rely on time-varying energy transfers. While e-Tag provides for both transaction types, many tagging requirements for both types are addressed in regional criteria and Transmission Operator Business Practices. For more detail on these types of transactions, see the NERC Dynamic Transfer Guidelines document.

Consideration for Interchange Involving DC Tie Operators

Note that DC tie operators that are Intermediate Balancing Authorities would receive the Interchange information and be subject to the applicable INT standards. The DC Tie operator also would be responsible for notifying the Sink BA of a DC tie trip and the associated Interchange modification.